Carbon Capture and Storage (CCS)

In a Nordic Perspective

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Preface

In January 2006 CICERO was commissioned by the Climate Change Working Group of the Nordic Council of Ministers to undertake a study of Carbon dioxide capture, transportation and geological storage – a Nordic perspective.

The main contributors to this report were from CICERO Asbjørn Torvanger (project manager) and Andreas Tjernshaugen and from SINTEF Jens Hetland and Marie Bysveen.

The Climate Change Policy Working Group does not necessarily share the views and conclusions of the report, but looks at it as a contribution to our knowledge about carbon capture and storage in a Nordic perspective.

Oslo, November 2007

Jon Dahl Engebretsen

Chairman of the Climate Change Working Group

Summary

Capture of CO₂ from industrial processes and geological storage may become a major option to mitigate man-made emissions of CO₂. This study aims at providing understanding of the current state of carbon dioxide capture and storage (CCS) in a climate context, and specifically pertaining to the prospects for CCS in the four Nordic countries Denmark, Finland, Norway, and Sweden.

Since CCS was introduced about two decades ago, a large portfolio of international research, development and demonstration plants has been established – mostly during the last decade. This study gives a brief overview of ongoing projects and initiatives.

The study gives a status for CCS in technical, economic, institutional, environmental, and public opinion terms. The technical aspects discussed are capture of CO₂ and additional use of fuel, capture costs in existing and new facilities, transportation costs, and relationship between size of CO₂ sources and capture cost. In terms of institutions the status of CCS in the global climate policy regime is discussed.

The second part of the report presents an overview of major stationary CO₂ sources, assesses the availability of suitable geological storage sites in Nordic countries, and finally discusses linking of sources and storage sites. There are a limited number of major stationary sources within the Nordic region, but with a much higher number in the wider North European region. The storage capacity in the North Sea is likely capable of receiving CO₂ from the Western European countries over more than 600 years. In addition eight smaller storage sites have been identified in Denmark, and two in Sweden. Finland, however, has not identified any suitable storage sites.

In conclusion there is an interesting potential for a CCS chain from capture to storage in the North European and North Sea region involving major infrastructure and storage components in the Nordic countries.

Introduction

Carbon capture and storage (CCS) may become a major option to mitigate man-made carbon dioxide (CO₂) emissions as a response to the challenge of climate change. It is therefore worthwhile to explore the potential of CCS as part of a climate policy. This report covers geological storage of CO₂, but not ocean storage. There are larger uncertainties with regard to permanency and environmental effects in the case of ocean storage, and only a few countries support this alternative, at least presently. Therefore we focus on geological storage only, and the acronym CCS should be interpreted as referring to geological storage only. In this report we furthermore limit the scope to assess the potential of CCS to mitigate CO₂ emissions in a Nordic perspective.

With present technologies CCS is relatively costly and may only be competitive as a climate policy measure under most favourable conditions, such as in combination with enhanced oil recovery (EOR), see Torvanger et al. (2005). Even a relatively high CO₂ permit price around 26 Euro per tonne in the European emission trading market (per February 2006; equivalent to USD 31) is not sufficient to cover CCS costs in the region of USD 50-80 per tonne CO₂. At the North Sea continental shelf there are oil reservoirs with a time window for EOR through CO₂ injection the next years that may provide a “birth help” for developing and implementing CCS technologies.

The interest in CCS technologies at the international policy arena has risen significantly the last few years. The US-led Carbon Sequestration Leadership Forum (CSLF) was established in 2003 and presently has 21 members.¹ In autumn 2005 IPCC presented a report that gives a good overview of CCS and also ocean storage. Furthermore IPCC is working on guidelines for national greenhouse gas inventories, where there is a separate section on CO₂ capture and storage. Under EU's European Climate Change Programme there is a working group on CO₂ capture and geological storage, which is to deliver a final report by May 2006. Provided approval by the European Commission the EU considers allowing for CCS credits under its emission trading system.²

The issue also entered the policy arena at the 11th Conference of the Parties (COP) to the United Nations Framework Convention on Climate Change (UNFCCC) and the 1st Meeting of the Parties (MOP) to the Kyoto Protocol in Montreal in November–December 2005. Many countries supported developing CCS technologies further as a climate change

¹ See <http://www.cslforum.org>.

² See page 11 in http://europa.eu.int/comm/environment/climat/pdf/c2004_130_en.pdf.

mitigation option, and also advancing necessary rules and institutions. It was decided to organize a seminar on CCS and a seminar on CCS-projects under the CDM (Clean Development Mechanism) under the subsidiary bodies meetings under UNFCCC in Bonn in May 2006. The next COP/MOP will provide further guidance on CCS in the context of climate agreements.

At the Nordic level Norway has expressed most interest for CCS, which is due to the storage potential at the North Sea continental shelf, planned gas-fired power stations in Norway, and the opportunity for EOR through CO₂ injection in oil reservoirs. This is reflected in a relatively high RD&D expenditure on e.g. CO₂ technologies (see Figure 2) and also reflected in more research reports. Norway and Denmark are the only Nordic members of the CSLF. In terms of other stakeholders, oil companies and major power producers in Nordic countries have expressed interest for CCS.

This report is building on numerous sources from the academic literature, technical reports, and government reports. The most important single source is the IPCC special report on CCS (IPCC 2005).

The report is divided into two main parts. The first part explores the status of CO₂ capture and storage technologies with sections on status for deployment, economic attractiveness, environmental aspects, thermodynamic costs, capture costs for existing sources, preparing new sources for capture, relation between size of sources and capture costs, and public acceptance of geological CO₂ storage. The second main part explores CCS in a Nordic perspective, and includes sections on sources in Nordic countries, opportunities for geological storage in Nordic countries, and linking sources and storage sites in Nordic countries.

Part 1: Status for carbon dioxide capture, transportation and geological storage technologies

1.1 Status for deployment of carbon dioxide capture, transportation and storage technologies

IEA's Greenhouse Gas R&D Programme, established in 1991, has played an important role in facilitating cooperation and disseminating information about CCS technologies. An overview of CCS research and demonstration projects can be found at the Programme's CO₂ capture and storage website.³

So far three CCS plants are now in operation at the global level:

The first one is the Statoil-operated Sleipner West field at the North Sea continental shelf that became operational in 1996.

The second one is the Weyburn CO₂-EOR project in Saskatchewan, Canada, initiated by Devon Canada Corporation and operated by EnCana Corporation. Since October 2000 the Weyburn project injects some 0.8 Mtpa CO₂ into the Willison Basin oil field over the 15 years lifetime piped from the Dakota Gasification Company's coal-gasification plant in Beluah, North Dakota, USA.

The newest one is the In Salah Gas Project in Algeria, operated by BP, which since 2004 re-injects up to 1.2 Mtpa CO₂ into a sandstone reservoir at a depth of 1800 meter. Whereas the CO₂ is separated from the produced gas that contains 10% CO₂, the natural gas is supplied to the Southern European market at commercial CO₂ level (2.5%).

The Sleipner project is a combination of a commercial CO₂ capture project and a demonstration storage project. Since 1996 about 1 million tonnes (1 Mt) of CO₂ annually has been separated from the well stream to reduce the natural gas' CO₂ content to an acceptable commercial level. The separated CO₂ has been injected into the Utsira deep saline aquifer formation to save the Norwegian tax on CO₂ emissions. The CO₂ is separated from the natural gas produced at Sleipner using the well-known amine absorption technology.

At the offshore Snøhvit gas field, which is the first gas field found in the Barents Sea, west of Hammerfest, Statoil and partners are planning to capture CO₂ from the gas to reduce the content to a commercial level and as a demonstration project inject the CO₂ into a sub-sea sandstone forma-

³ See <http://www.co2captureandstorage.info/>.

tion 2,600 meters beneath the seabed. The Snøhvit field will start production in 2007, and the injected volume will be about 0.7 Mt CO₂ annually.

Related to the Snøhvit project Hammerfest Energi and partners are planning a commercial 100 MW combined cycle gas power plant with CO₂ (and NO_x) capture. The gas will be available from the Snøhvit field. The CO₂ will be transported in a separate pipeline and injected into the sub-sea sandstone formation used in the Snøhvit project.

Figure 1: Some current CCS projects by start-up year (centre of bubble versus abscissa) and technology (versus ordinate) arranged according to main-focused technology: 1) Pre-combustion decarbonisation, 2) in-combustion combustion cleaning, 3) post-combustion flue gas cleaning, and 4) storage. The yellow spheres refer to major national and European projects. The orange-coloured projects refer to industrial projects (i.e. Cottbus VF, BP Miller and Statoil/Shell) whereof just the Cottbus budget is roughly known (40 M€). The two larger bubbles refer to the \$1000 mill US-based FutureGen project and the 1300 M€ EU-based Hypogen project planned to get started in 2009. Except for the two large projects, the sizes of the spheres are roughly to scale. The centre of each bubble decides the year of project launch (abscissa), and the ordinate decides the main technology route, although some projects cover more technologies.

As depicted in Figure 1 the 44 M€European ULCOS research project is mainly addressing carbon capture from industrial processes, whereas the remaining projects in the figure refer to the energy sector.

The Swedish company Vattenfall is planning a CO₂ capture facility between Dresden and Berlin in Germany, known as the Cottbus project. This is a pilot 30MW coal-fired power station. The original plan was to store the captured CO₂ in an aquifer outside Berlin, but due to inconvenient timing such storage will not take place.

BP and partners are planning to build a gas-fired power station with CCS technologies in Scotland, which is known as the BP Miller project. CO₂ will be separated before combustion and only hydrogen used for

power production. The captured CO₂ will be injected into oil reservoirs for the purpose of EOR.

In the area of research projects the European Commission is funding the CO₂STORE project, which is co-ordinated by Statoil and running from 2003 to 2006. The objective is to investigate new storage reservoirs in Denmark, Germany, Norway and the UK, and also predict the long-term fate of CO₂ stored in the Sleipner project (Utsira formation).

The European Commission is also funding the CO₂SINK geological storage research project. The project is co-ordinated by GeoForschungsZentrum Potsdam and involves a number of industry and academic partners. In this five-year project 30,000 tonnes of CO₂ annually over three years will be injected into a shallow sandstone reservoir close to Berlin in Germany. The objective is to better understand the science and practical processes involved in underground storage of CO₂.

CASTOR is another research project funded by the European Commission, running in the period 2004 to 2008. IFP (France) is the coordinator. The objective is to make possible the capture and storage of 10% of European CO₂ emissions, or 30% of the CO₂ emissions of large industrial facilities. The focus is on reducing the cost of CO₂ capture, but in addition the aim is to develop tools and methods to quantify and reduce risks related to storage.

CO₂GeoNet is a research network on geological storage established in 2004 and funded by the European Commission. The five-year network activity will focus on geological storage of CO₂ as a greenhouse gas mitigation option.

In the years 1999-2002 Finland funded a national research program, Climtech, to “promote research, development, commercialization, implementation, and export of technologies supporting the mitigation of climate change”. CO₂ capture and utilization was one of six subject areas. The main finding was that there are no suitable geological storage sites in Finland (see Soimakallio et al. 2003).

The UK and Norwegian Minister of energy in November 2005 agreed on collaboration on CCS in the North Sea Basin. A North Sea Basin Task Force is established, with the aim to develop comprehensive, common principles as a basis for regulating CO₂ storage in the North Sea. The two countries will collaborate in international forums such as CSLF and IEA to facilitate sub-seabed storage of CO₂, and also under the UNFCCC, the Kyoto Protocol, and in the context of other international environmental agreements.

Early 2005 the 22 M€EU-based project ENCAP was launched jointly led by Vattenfall AB (co-ordinator) and SINTEF Energy Research (management). The objective is to cut lead-time and improve cost of emerging pre-combustion power generation with carbon capture for continued use of fossil fuels in Europe - and elsewhere, and to ease the interface with transport and storage of CO₂. The stated target is to achieve at least 90%

capture rate and 50% capture cost reduction reckoned from a current level of 50-60 €/per tonne of CO₂ captured.

In March 2006 the 8 M€EU-based DYNAMIS project was kicked off, aimed at preparing the ground for large-scale European facilities producing hydrogen and electricity from fossil fuels with CO₂ capture and permanent storage, eventually with the option for the CO₂ to be used for enhanced oil or gas recovery (EOR/EGR). SINTEF Energy Research is the co-ordinator. It is structured to prelude to the subsequent 1300 M€ Hypogen Demonstrator project aimed at a large-scale demonstration of this technology by year 2012. In addition to four tangible topics, the project also addresses societal anchorage, including legal, regulatory, funding and economic aspects, and public issues.

Furthermore, the Norwegian BigCO₂ was launched by 2001 and co-ordinated by SINTEF Energy Research. The main funding is received from the Research Council of Norway with industrial co-funding. The objective is to establish a Norwegian action plan for carbon-capture technologies, concepts and knowledge on gas power generation - including CO₂ transportation and storage - ranked according to ability of fulfilling a compound target: 90% CO₂ capture rate, 50% cost reduction and a fuel-to-electricity penalty less than 7 percent compared with state-of-the-art gas power generation.⁴

So far owing to the Norwegian plight of being one of the world's largest exporters of oil and natural gas while being a net importer of electric power, a strong debate prevails regarding the Norwegian energy sector. One consequence is that Norway has become quite instrumental in broaching new technology research pertaining to CCS. According to Tjernshaugen (2005) Norway was in 2005 responsible for as much as 18% of the North American and the pan European governmental research expenditure on CCS - next to the US (45%) and the EU and its member states (25%) as shown in Figure 2.

Figure 2: North American and European Governmental CCS RD&D spending (2005) aggregated at approx. 115 M€ (Source: Tjernshaugen 2005).

⁴ State-of-the-art efficiency at almost 58% (LHV) reckoned at Norwegian climatic conditions.

1.2 The economic attractiveness of carbon dioxide capture, transportation and geological storage

The economic attractiveness of CCS depends on two main factors, namely the demand for CO₂ mitigation as a function of climate policy, and on the supply side it depends on the competitiveness of CCS compared to other greenhouse gas mitigation options.

The demand for CCS is motivated by climate policy in the short and longer term. In the short term EU member states have binding commitments to limit their emissions in EU's emission trading system in the period 2005-2007. These commitments have been transferred to the energy-intensive industries and companies included in the trading system (covering about 45% of EU's CO₂ emissions) through national allocation plans. In the second phase of EU's trading system, coinciding with the Kyoto Protocol target period 2008-2012, industrialized countries (with the exception of the USA and Australia, which have declined to ratify the Protocol) have national commitments to reduce their greenhouse gas emissions. The three flexibility mechanisms emissions trading (ET), joint implementation (JI) and the Clean Development Mechanism (CDM) allow for leveling out of marginal greenhouse gas abatement costs through trading of emission allowances (ET) or emission credits (JI and CDM). CDM and JI credits are allowed in EU's emission trading system, but possibly with some limitations. The price of the EU allowance (1 EUA is equivalent to an emission of 1 tonne of CO₂) is a good short-term indicator of the climate value of storing one tonne of CO₂. Presently the price is at about 26 Euro. This price should reflect the cost per tonne of CO₂ for the least expensive technology and project that can supply new allowances to the emission trading market. Therefore the price of CCS must be in the region of the allowance price to be competitive. However, at least to the end of the Kyoto period the potential of CCS is likely to be very limited due to lacking rules and institutions internationally, and due to relatively high cost. The joint value of storage as a climate mitigation option and through EOR in oil reservoirs provide an opportunity for "birth help" of CCS technologies in the North Sea. On a global scale, however, the potential of CO₂ storage in oil reservoirs well suited for EOR is very small compared to the potential in aquifers and other geological formations.

In the longer term the stringency of international climate policy and agreements will be decisive for the value of CCS, and as indicated by the price of allowances and credits in the trading markets (see IEA 2005). The stringency further depends on global mitigation target compared to business as usual, the time horizon of the climate policy strategy, and the broadness of participation. Will countries like the USA, China and India participate, and in what way? In this longer time perspective the potential of CCS is likely to be much higher than until 2012. At COP11 and the

first meeting of parties to the Kyoto Protocol in Montreal in autumn 2005 the parties agreed on two new processes for developing the climate regime beyond 2012, one for future action under the UNFCCC and one for further commitments for Annex I countries under the Kyoto Protocol.⁵ At the subsidiary bodies meetings to the UNFCCC in Bonn in May 2006 two workshops on CCS were organized, where the first was on CCS in relation to the climate regime and the second was on the relation between CCS and CDM. However, there is still substantial uncertainty attached to the future of international climate policy.

On the supply side a major issue is the scope of reducing the CO₂ capture cost. There are existing post-combustion amine-based technologies that are commercial, but at a high cost. The cost is likely to be reduced through learning by doing and economies of scale given that a sufficient number of full-scale facilities are built. There is also a substantial potential to reduce the cost through developing new and more efficient technologies, via new power cycles such as oxy-fuel or pre-combustion techniques, and by new materials, processes and separation technologies (membranes and absorbents) to mention a few. In terms of transportation, compression of CO₂ and storage the potential for cost reduction is much smaller. In any case there will be a cost saving potential due to economies of scale if CCS facilities are built on a large scale, and possibly involving cross-border collaboration in the North Sea region. Government involvement provides an additional perspective on the cost of CCS. If a government finds that the development of competitive CCS technologies is of long-term, strategic value it may subsidize demonstration facilities and deployment of these technologies, which may render them more competitive compared to other mitigation options such as wind and bio energy and other renewable energy sources. The risk of this strategy is that the government “picks the winner” and technology “lock-in” arises when favouring a specific technology.

The costs of competing mitigation technologies are also likely to go down over time due to learning by doing, economies of scale, and development of improved techniques. These technologies can be related to renewable energy sources, and more energy- and emission-efficient equipment in both production and consumption of goods and services. Consequently the economic attractiveness of CCS depends not only on reductions in the cost per tonne of CO₂ from CCS but also on how the costs of alternative mitigation options develop over time. At the end of the day the competitiveness of CCS depends on the relative cost per tonne of CO₂ compared to the alternative emission mitigation options.

⁵ Annex I are industrialized countries as defined in an annex to the UNFCCC. Each industrialized country has binding commitments to reduce its GHG emissions under the Kyoto Protocol.

1.3 Environmental aspects of geological storage

Leakage of CO₂ to the atmosphere from storage sites or transportation will affect the effectiveness of CCS as a climate policy measure. In addition, leakage may cause local effects on ecosystems and human health. Finally, some local and regional effects could stem from the storage itself, even if there is no leakage.

Leakage of CO₂ from transport and storage could be in the form of abrupt release of large volumes of CO₂ due to explosions, earthquakes, equipment failure or the like. A very different scenario is gradual seepage from storage sites through boreholes, faults in the cap rock, natural flows, or other passages (see section 5.7 in IPCC 2005).

Notice that different aspects of leakage are important to climate change and to local and regional effects. In terms of man-made global warming, the important determinant is the total amount and timing of CO₂ released to the atmosphere from any part of the world over decades and centuries. In terms of local and regional effects of CO₂ leakage, what matters is the amount released in the short term at a certain locality and its exposure to ecosystems and human populations.

Similar industrial activities such as underground storage of natural gas, or CO₂-assisted enhanced oil recovery (EOR) offer useful experience with regard to the environmental risks of CCS. These industrial analogies are particularly useful for assessing the local and regional risks. There are also natural analogies, i.e. permanent underground reservoirs for CO₂, as well as locations with natural seepage of CO₂.

1.3.1 Likelihood of leakages

Our knowledge of the likelihood of leakages from geological storage sites is limited. Due to analogies with gas transport we have more knowledge on the risks involved in transporting CO₂ by ship or pipeline. In terms of long-term effects the important parameters are the fraction of geological storage sites that have a non-marginal leakage and the escape ratio and profile of each of these sites. In terms of the short-term local effects the scope can in practice be limited to the probability of substantive leakages from sites in the vicinity of major ecosystems or human populations. Estimates of leakage scenarios can build on natural systems such as gas reservoirs, engineered systems such as storage systems for natural gas, and numerical simulations.

Building on this evidence and insights from CO₂ leakage studies the IPCC (2005) report concludes that: “It is very likely that the fraction of stored CO₂ retained is more than 99% over the first 100 years. It is likely that the fraction of stored CO₂ retained is more than 99% over the first 1000 years”.

1.3.2 Climate consequences of leakage

Long-term seepage of CO₂ from geological storage sites may have climate consequences if sufficient volumes of CO₂ are stored globally. There are few literature references in this area, but new research is ongoing.⁶ Lindeberg (2003) models global fossil fuel use, CO₂ storage and leakage from geological reservoirs causing increased global warming. If all fossil fuels are used and 80% injected into geological formations he finds that a relative high seepage rate (i.e. a short retention time of 1800 years) will induce a temperature increase of a substantial 2.5 °C. Therefore he concludes that a minimum retention time of 10,000 years should be a prerequisite for generating climate credits from geological storage of CO₂.

1.3.3 Local and regional effects of storage and leakage

IPCC (2005) discusses four types of local and regional environmental risk related to CO₂ storage (Benson, Cook et al. 2005):

- Potential hazards to human health and safety;
- Hazards to terrestrial and marine ecosystems;
- Hazards to groundwater from CO₂ leakage and brine displacement;
and
- Induced seismicity.

The first two types of risk relate specifically to leakage of CO₂ to the atmosphere, either through catastrophic release or through gradual seepage of substantial amounts of CO₂. The third and fourth bullet point refers to consequences of storage that are not necessarily associated with release of CO₂ to the atmosphere.

Hazards to human health and safety could arise because high CO₂ levels in the air cause respiratory problems. The background CO₂ concentration in the atmosphere is at 0.04% (i.e. 380 ppmv). Concentration must be much higher to inflict health effects on humans. Concentrations above 7-10% may be lethal. CO₂ is heavier than air, and in the absence of wind it tends to fall towards depressions in the landscape and could accumulate to higher concentrations in confined spaces. For this reason, not only catastrophic release of CO₂ but even gradual seepage could be dangerous, depending on the amount of gas released at one location and local weather and topography. In areas with volcanic activity, human and animal mortality from elevated CO₂ levels due to natural release has occurred. Such areas would obviously be unsuitable for CO₂ storage.

⁶ CICERO and SINTEF are undertaking a research project to explore climate consequences of long-term CO₂ leakage scenarios from geological storage sites (funded by the Research Council of Norway and industrial partners). The first results will be available by summer 2006.

IPCC (2005) points to mining or drilling activity in a distant future, when CO₂ storage sites are no longer monitored, as one potential risk to human beings (:246-7).

Leakage may also lead to hazards to marine and terrestrial ecosystems. CO₂ seepage related to volcanic activity or engineering projects on land is known to increase CO₂ concentrations in the soil to very high levels where the vegetation dies off, and which also kills organisms living in the soil. No such effects have been recorded at CO₂ storage or EOR locations, though. Highly elevated CO₂ concentrations in the air could also kill plants and animals. Seepage from offshore geological storage could particularly hurt benthic ecosystems, that is, organisms living on or close to the seabed (:248-9). At the time when the IPCC report was finalized, no published studies investigated the ecosystem effects of release of CO₂ from offshore geological storage. Ongoing research seeks to fill in knowledge gaps in this field (Kendall 2005). It is known that increased acidity of seawater due to CO₂ could inhibit the calcification process building coral reefs (including cold-water reefs found in northern waters), and could also influence several other ecologically important groups of marine organisms. However, regardless of the geological storage issue, acidification of seawater due to increased CO₂ concentrations in the atmosphere is an ongoing process with potentially serious consequences for marine life. It has been argued that this effect of release to the atmosphere outweighs the risk of partial leakage from offshore geological storage sites (Riley 2005).

Hazards to groundwater could come from two mechanisms. First, CO₂ that migrates from deep storage sites towards the surface could come into contact with shallow groundwater and increase its acidity. This could in turn affect the chemical reactions between the freshwater and the surrounding minerals. The result could be changes in the water's color, smell or taste, or, in the worst case, increased contents of heavy metals or other toxic elements. Second, injection of any fluid including CO₂ will necessarily increase the pore pressure around the storage site. This could lead to displacement of brine, which could contaminate freshwater layers, making them too salty for drinking. The worst-case scenario is that brine gets so close to the surface that it affects vegetation or aquatic life in surface waters. The risk of groundwater contamination depends on local geological circumstances (:247-8).

The increased pressure from injection of CO₂ or any other fluid in porous rock could induce local seismic activity (small earthquakes) as the rock adjusts to the new pressure. The IPCC report points to experience from other activities including CO₂-assisted EOR as helpful in assessing and controlling the risk of induced seismic activity (:249-50).

Finally, IPCC (2005) points out that in some cases, the CO₂ stored might be contaminated with trace gases such as H₂S, SO₂, and NO₂. The resulting mixture may be more acidic or more toxic, which would am-

plify several of the risks discussed above. To date, there are few published studies that consider this aspect (:250).

1.4 Fuel penalty of CO₂ capture

An immediate conclusion drawn from concerted European research is that capture of CO₂ (referred to as just carbon-capture) is technically feasible, although it still remains to deem carbon capture a viable option on technical, environmental and economic terms. Persistent obstacles are capture cost and fuel penalty (i.e. additional fuel required for CO₂ capture), as well as the recognition of storage of the CO₂ in geological structures as an adequate and safe approach.⁷ Typical of carbon capture is a fuel penalty that amounts to as much as 15-30% additional fuel – depending on technology and presumption.

Essentially, referring to the use of fossil fuels in large-scale power cycles three main principles for CO₂ removal prevail, characterised by the carbon removal approach versus the combustion process:

1. Pre-combustion removal (characterised by decarbonisation leaving a hydrogen-enriched fuel for the power cycle)
2. In-combustion removal (via de-nitrogenation of air, referred to as oxy-fuel)
3. Post-combustion removal (scrubbing of the flue gas from conventional power cycles)

The main principles of these approaches are presented in Figure 3, and the prospective efficiencies versus anticipated development time have been attributed to the *actual* and *potential* technologies as shown in Figure 4. A main basis of the latter development trends is that each technology will be pursued under high leverage, and without any reasonable constraints in terms of funding support.

⁷ CO₂ removal by absorption in industrial processes is deemed proven technology. Reference is given to the Saline Aquifer CO₂ Storage project at the Sleipner field in the North Sea, Norway (SACS).

Figure 3: The three prevailing principles for CO₂ removal relating to the use of fossil fuels in large-scale power cycles characterised by the removal approach versus the combustion process.

1) In *pre-combustion decarbonisation* a synthesis gas - rich in hydrogen and carbon monoxide (CO) - is first provided via reforming of natural gas or gasification of coal. Thereafter the synthesis gas undergoes a subsequent water-gas-shift reaction in which the CO and a hot steam are transformed into CO₂ and hydrogen. As the hydrogen will then be used to fuel the power cycle, it must be isolated from the CO₂ via a separation process. Hence, the cost penalty of removing the CO₂ according to this approach is deemed lower than in the alternative post-combustion capture. Most likely a similar statement will apply versus the oxy-fuel capture approach due to the extensive energy demand for the oxygen production that constitutes an integral part of said approach.

One important element of pre-combustion carbon capture is the higher concentration of CO₂, which is prone to affect the cost structure in a favourable manner. Technologies that operate at higher CO₂ concentration, as the case will be with pre-combustion capture concepts, are prone to offer an inherent advantage over the alternative post-combustion technologies in which the concentration is rather low. Hence, owing to the higher partial CO₂ pressure of the reformer gas, pre-combustion decarbonisation concepts may employ more compact and less energy-intensive equipment for the removal of CO₂ than the case would be with post-combustion cleaning.

Pre-combustion decarbonisation technologies are prone to attract particular interest in systems that include hydrogen. Hence, pre-combustion decarbonisation is foreseen to constitute the major route to hydrogen production in the foreseeable future – such as the EU-based HYPOGEN plant scheduled to go on stream by year 2012 (Hetland 2006).

2) The *oxy-fuel approach* involves pure oxygen as oxidant, which means that the exhaust gas contains basically water vapour and CO₂. By cooling the exhaust gas to below its dew point, the water is condensed and re-

moved from the system, thus leaving just CO₂. Although this concept appears simple in principle, it is a rather complex process that requires accurate control. Because of the high firing temperature that owes to the oxygen-supported combustion, a part of the exhaust gas must be re-circulated in order to keep internal temperatures of the power cycle at a level that critical components can sustain.

Oxy-fuel capturing is prone to attract interest from energy providers, as it offers a plausible alternative to post-combustion removal, in particular relating to coal gasification. And, despite that limited research has been verified in oxy-fuel-pulverised-coal-boiler technology, the approach is seemingly interesting for CO₂ capture provided that the oxygen and fuel mixture can be well balanced with the inert gas coolant supplied from the flue gas.

A major obstacle is the high-fuel penalty pertaining to the cryogenic oxygen production. An alternative concept via chemical-looping combustion may, hopefully, reduce the fuel penalty considerably.

3) *Post-combustion flue gas cleaning* differs from the previous concepts in the sense that the power cycle is just a conventional power plant or an industrial plant, as just the exhaust gas is subjected to cleaning. What is new is the full integration of the power cycle and the attached cleaning unit, which, eventually, requires some additional power and steam, basically for the chemical absorption/desorption processes. Hence, among the three main principles for carbon capture as listed above, post-combustion is considered the most mature approach, and it is, evidently, associated with the highest fuel penalty. The main advantage is, however, the ability of post-combustion concepts for retrofitting existing power plants by adding a cleaning unit to the exhaust system. Post-combustion cleaning is, thus, the only concept that may be applied in conventional power thermal power generation plants. It should be notified, however, that the size and cost are still considered prohibitive.

1.4.1 Technical approach

In large-scale power generation no carbon capture technology has so far been deemed feasible on commercial terms. Hence, there is a pronounced need to improve efficiency and reduce cost. As indicated in Figure 5, various concepts have been proposed for CO₂ capture. Whereas oxy-fuel and post-combustion concepts represent the primary conversion of the fossil fuel, pre-combustion employs a secondary conversion of the fuel via a hydrogen-enriched fuel gas.

Figure 4: Expected efficiency potential and development of various capture technology routes as reckoned from the outset of targeted RD&D (Source: SINTEF Energy Research, ENCAP proposal, EU FP6).

The selection of candidate carbon capture technologies depicted in Figure 5 has been assembled from different sources (Hetland 2005; Hetland 2006). The quoted energy efficiency may vary depending on the bases and presumptions made for each analysis. Reference is made to Kvamsdal et al. (2004) who have presented a broader and more comprehensive study of CO₂ capture technologies for natural gas, whereas Damen et al. also discuss coal-based technologies (Damen et al. 2004).

In Figure 5 the various technologies are divided into near-term, mid-term and future concepts, and compare with the state of the art in thermal power generation.

- State of the art refers to a natural gas-fuelled power scheme designated combined cycle, CC. The combined cycle includes a Joule-Brayton cycle preceding a Rankine cycle linked with a heat recovery steam boiler that extracts heat from the exhaust gas of the Joule-Brayton unit.
- The near-term concepts include PC-MEA (pulverised coal combustion with flue-gas cleaning based on amine, MEA), IGCC (integrated gasification in combined cycle configuration), NG-MEA (natural gas combined cycle combined with amine scrubbing), ATR (auto-thermal reforming), and Sargas. The latter uses a Rankin cycle with pressurised combustion with flue gas scrubbing (post combustion) (Bendiksen 2005).
- The mid-term concepts are basically in-combustion capture cycles (oxy-fuel) comprising the ZENG WC (water cycle), Oxy-fuel CC and the Graz concept as described in (Kvamsdal et al. 2004).

- The future concepts include the Combicap concept that integrates two or more combined gas turbine cycle blocks with a new combustor arrangement and a CO₂ capture plant that operates at elevated pressure as described by Lynghjem et al. (Statoil) (Lynghjem et al. 2004). Among the future concepts are also the chemical-looping-combustion cycle integrated with a natural gas combined cycle (NGCC-CLC), the pre-combustion concept with hydrogen membrane reactor (MSR-H₂), the advanced in-combustion zero emission power cycle (AZEP), which is a membrane-based oxy-fuel technology, and also the NGCC-SOFC and IGCC-SOFC, which are solid oxide fuel cells integrated with a combined cycle – using either natural gas or gas produced by coal gasification that ends up with a hydrogen-enriched gas.

Figure 5: Efficiency potential assumed by studies of various carbon capture concepts with state of the art in combined cycle gas power generation as reference (CC base case). Near term concepts are based on reforming or gasification and post-combustion scrubbing. The percentage attributed to the name of the concept indicates the claimed capture rate. Efficiencies refer to LHV. (Source: Hetland 2005)

A mention is needed to the percentage attached to the technology name, which is an indication of the expected capture rate. The percentage should be construed as the presumption made on capture-rate for the referred assessment studies.

1.4.2 Natural gas versus coal

Owing to its low carbon number (basically C₁) natural gas has so far been seen as a clean fuel in most countries and, thus, used as a fuel switch

because of its significant mitigating potential over other fossil fuels as depicted in Figure 6.

Since long coal gasification has been commercially available technology⁸. Large gasification plants are deployed worldwide. The feedstock is either supplied as dry coal or as a slurry mixed up by coal particles and water. In Europe two large coal gasification plants produce electric power - one in Puertollano, Spain, the other in Buggenum, the Netherlands, the latter being co-fired by coal and biomass⁹. In Rheinbraun, Germany, another gasification plant produces syngas for methanol production. Large coal gasifiers are further being planned for the UK (reportedly in Wales) and Italy (Hetland 2006).

Figure 6: CO₂ formation in kg CO₂ per GJ fuel by a complete conversion of basic hydrocarbons by carbon number (Source: Hetland 2005)

1.4.3 Recent examples of emerging capture projects

1. Pre-combustion: The BP Miller field off the east coast of Scotland, motivated by the options for EOR.
2. In-combustion: The Cottbus project of Vattenfall at Berlin (Germany) based on oxy-fuel capture with chemical-looping combustion using a fluidised bed technology.

⁸ Industrial gasifier types are: fluidised bed, fixed bed, entrained flow gasifier. The latter is considered the best option for hydrogen production because it combines high efficiency with low methane content in the product flow.

⁹ Puertollano: 335 MW_{el}, Buggenum: 250 MW_{el} co-fired with biomass.

3. By March 2006 a pilot plant for post-combustion capture was inaugurated at a power plant at Esbjerg (Denmark). The pilot, being part of the EU-based Castor project, is specially made to clean a slip stream from the power plant corresponding to 1 tonne of CO₂ per hour via amine scrubbing.

Furthermore, by early March 2006 Statoil and Shell announced a joint idea of building a 860 MWe gas-fired power plant at Statoil's methanol complex at Tjeldbergodden. According to company information, this is a \$1200-\$1500 million project that will become the world's largest scheme to bury industrial gases beneath the seabed off Norway to enhance the oil output and to respond to the climate change issue. This project could store some 2-2.5 Mtpa of trapping carbon dioxide, and it may become the first to use carbon dioxide to boost oil recovery offshore, though CO₂ has been injected into onshore oilfields in the US (Texas). According to the released schemes, the CO₂ is to be piped to Shell's Draugen oilfield off Norway - and later also to Statoil's Heidrun field - and injected into the sub-sea reservoirs to force more oil to the surface.

The power plant alone would cost MNOK 4000-4500, whereas the CO₂ capture system and the pipeline to the field would cost a similar amount, according to Statoil.¹⁰

1.5 Costs of capture facilities at existing carbon dioxide sources and transport in a Nordic perspective

1.5.1 Capture cost

The cost of CO₂ capture includes additional capital expenses as well as the additional operating and maintenance costs of a specific application. The most significant elements of the capture cost are the fuel penalty and the CO₂-compression work. Whereas the capture cost includes the initial CO₂ compression, the cost of additional booster compressors (if any) usually belongs to the transport and storage cost. Various aspects relating to concept and technology may influence the overall capture cost as well, which becomes evident when comparing the cost of various projects, even though they may look rather similar.

As depicted in Figure 5 the capture concepts are still too inefficient, as they require 15-30% more fuel than the state-of-the-art combined cycle power plant without capture. Capture also implies a premium cost of at least 50 €/per tonne CO₂.

The assumed capture cost may, however, differ somewhat from study to study depending on technology refinement, plant size and further pre-

¹⁰ Ref. http://news.yahoo.com/s/nm/20060308/sc_nm/energy_statoil_shell_dc

sumptions made for each case. The deviation may also explain the uncertainty of such cost estimates, as so far no plant has been built at full scale. Hence, as basis for recent EU-FP6 projects such as ENCAP and DYNAMIS, 50-60 €/tonne CO₂ was assumed as the current cost level. Said projects are targeting a cost reduction of 50%, thus suggesting that 25-30 €/tonne CO₂ is within reach. In contrast, an IPCC report (IPCC 2005) suggests that the current capture cost ranges from US\$ 50-100 per tonne CO₂, which extends the range and uncertainty indicated for ENCAP and DYNAMIS towards the higher and the lower direction. The same report also suggests a future level in the range of US\$ 25-50 per tonne CO₂, which compares better with the ENCAP and DYNAMIS target. And, furthermore, an IEA report (IEA 2004) seems to be even more optimistic as it states: Improving technology can reduce capture costs substantially, to 5-30 USD/t CO₂. The lower and the higher figure depend on uncertainty and prerequisites made for the cost estimation. Costs could decline to 10-25 USD for coal-fired power plants and to around 25-30 USD/t CO₂ for gas-fired power-plants; they could be even lower for biomass fired processes. The gap between capture and abatement cost narrows as the energy efficiency penalty for CO₂ capture decreases.

The capture cost can be expressed in terms of additional cost of CCS in electricity production per MWh. Figure 7 shows the additional CCS cost in Euro per MWh in the case of natural gas (methane) based electricity production as a function of capture cost in Euro per ton of CO₂ and plant efficiency at current technology level and for expected technology improvement. As an example, a capture cost range of 30 to 70 Euro per ton implies an additional CO₂ capture cost of 10 to 33 Euro per MWh, equivalent to 0.08 to 0.26 NOK per kWh (1 Euro = 8 NOK).

These assessments suggest that cost figures must be handled with great care.

Figure 7: Capture cost in Euro per MWh versus capture cost per ton of CO₂ and plant efficiency for natural gas (methane) based electricity production.

1.5.2 CCS from coal versus natural gas

The capture cost per tonne of CO₂ is prone to become lower for coal-fired processes than for gas-fired processes, owing to the higher concentration of CO₂ with coal. One can expect that technology improvements may depress the capture cost substantially, according to IEA (2004) in the range of 5-30 USD/t CO₂. The capture cost could decline to 10-25 USD for coal-fired power plants and to around 25-30 USD/t CO₂ for gas-fired power-plants; and it could become even lower for biomass fired processes. Hence, the capture cost is approaching the abatement cost as the fuel penalty for CO₂ capture decreases.

1.5.3 Investment cost natural gas-fired plants (post combustion)

According to an IPCC report the cost of electricity generation will increase by approximately 40-70 % for a modern natural gas-fired combined-cycle power plant (state of the art) using an amine-based scrubber post combustion (IPCC 2005).

According to Statoil the price tag of a 860 MWe gas-fired combined-cycle power plant with post-combustion flue gas cleaning, which was announced by Statoil and Shell by March 2006, amounts to NOK 4-4.5 billion (500-560 M€), whereas the CO₂ capture system and the pipeline that is needed to bring the CO₂ to the oilfield for enhanced oil recovery, would have a similar price¹¹. The price of the exhaust cleaning system alone corresponds to roughly 75% of the power plant. Hence, this makes

¹¹ Ref. http://news.yahoo.com/s/nm/20060308/sc_nm/energy_statoil_shell_dc

an approximate cost breakdown for a modern large-scale gas-fired combined cycle power plant as follows:

1. Power plant	580-650 k€MWe installed power
2. Capture train
combustion)	440-490 k€MWe (amine scrubbing post
3. Infrastructure	145-160 k€MWe

1.5.4 Future plants including provisions for hydrogen

The most widely studied systems are new power plants based on coal combustion or gasification. For a modern (high-efficiency) coal-burning power plant - with CO₂ capture using an amine-based scrubber - the cost of electricity generation will increase by approximately 40 % while reducing the CO₂ emission per kWh electric power by about 85 %. For a new coal-based plant employing an integrated gasification combined cycle (IGCC) system, the cost of electricity will increase by 20-55 % with a similar reduction in CO₂ using current technology (i.e. a water gas shift reactor followed by a physical absorption system). The lower incremental cost for the IGCC system is explained by the lower gas volumes and the lower energy requirements for CO₂ capture relative to combustion-based systems (IPCC 2005)

So far 95% of the world hydrogen production is derived from natural gas via steam reforming. In a future perspective coal may constitute an alternative, as it becomes mandatory to apply carbon capture with a highest practical capture rate in order to maintain the image of hydrogen as a clean fuel (Hetland 2005). Currently, the cost of producing hydrogen from coal is somewhat higher than by steam reforming (refer Table 1). It is anticipated, however, that this ratio will shift to the opposite. The reason is the lower primary energy cost of coal, and a further expectation of cutting cost according to the learning factor and the economy of scale. It is quite interesting though, that coal is prone to offer the cheaper alternative at high capture rates. This suggests that in a future regime with carbon trading decarbonisation of coal is expected to become even more favourable.

Table 1: Comparing natural gas reforming and coal gasification for the hydrogen production (Hetland 2005 and Hetland 2006).

Feature	Natural gas reforming	Coal gasification
Proven technology	Yes	Yes
Impact on cost (hydrogen and electric power)	Currently relatively low cost without carbon capture. By 2020 CC cost assumed at 30-40€/tonne CO ₂	Currently: Without carbon capture somewhat higher cost than that of natural gas. By 2020 carbon capture cost expected to drop to 15-30€/tonne CO ₂
Primary energy supply / access	Easy / well developed infrastructure in most parts of Europe.	Fairly easy and favourable price / large reserves readily available and distributed world wide ¹² .
Possible implications on large scale use	May have a negative impact on the issue of primary energy supply, and also on the overall greenhouse gas emissions, as some methane inevitably will dissipate from the system	Less geo-political limitations are foreseen than with natural gas. Coal gasification may become attractive to some developing regions having large coal reserves and limited resources for oil and NG (e.g. South Africa, China)
Expected plant size and investment cost	Large size and high materials cost are imposed by the pressure and temperature level used. Can also be offered at relatively small quantities (1000 Nm ³ /h) hydrogen.	Large size, high investment cost due to complexity will limit the application to large-scale facilities – requiring a high demand for hydrogen in the market.

1.5.5 CO₂ transport ex plant

Backed by 30 years of experience, the piping of CO₂ is deemed proven technology (Hetland 2005, and IEA Greenhouse Gas R&D Programme 2003). In the US millions of tonnes CO₂ are piped each year and used for EOR. A total of 3000 km of pipelines are dedicated for CO₂ world-wide with an aggregated capacity of some 50 Mtonne p.a. (Gale et al. 2002). In offshore processing, which is relevant in the Nordic perspective, the European experience from commercial operations is mainly limited to the Sleipner field in the North Sea where 1 Mt CO₂ p.a. is being stored underneath the sea bed since 1996. Several studies conclude that offshore pipeline transport of CO₂ is feasible. Statoil is therefore planning to pipe some 0.7 Mtpa CO₂ extracted from the natural gas for injection to the Snøhvit offshore formation some 160 km away from the LNG facility at Melkøya (Hammerfest) where the CO₂ is to be captured¹³.

So far three CO₂ marine vessels have been built with semi-pressurised tanks for liquid CO₂ shipment – one operated by the Rotterdam-based

¹² Owing to the substantially increasing coal consumption the reserves over production ratio (R/P) dropped from 192 to 164 years from 2003-2004. Whereas in 2002 the ratio was as high as 216 years. Reference is made to the *BP statistical review of world energy 2005*.

¹³ Snøhvit project, Norway; a 4.3 Mt p.a. LNG plant to go on stream by 2006. Reference is made to (www.statoil.com)

Anthony Veder Group¹⁴ and two operated by the Norwegian company Yara¹⁵. The vessels are in the 1000–1500 m³ class with a tank pressure 0.7 – 1 MPa. Assessment studies suggest that the optimal size of future commercial CO₂ carriers would be in the range 10 000–30 000 m³ gas with a tank pressure of 0.7–1.0 MPa.

Whereas seaways transportation of CO₂ - by ship or by subsea pipelines - and also the transportation across the national boundaries will be governed by international law, various international conventions may impose implications on CO₂ storage¹⁶. The implication hereof is that it will take time to build capacity and infrastructure.

In order to transport the CO₂ the gas must be dried, cleaned and made liquid (at supercritical conditions) depending on the requirement set by the transport means and for the storage site. This requires a considerable understanding, and pre-normative work that may lead up to a regulatory framework, codes and standards pertaining to the CCS chain.

1.5.6 The cost of CO₂ transport

The cost of CO₂ transport depends on volume, distance, soil type, topography, sea or land, land prices, permits and numerous other factors. According to IEA (2004) these transport cost elements may amount to about 2–10 USD/t CO₂, although low volumes, difficult terrain and other factors may increase the cost significantly (up to 20 USD/t CO₂ further to the IEA).

In a European context it is likely to believe that offshore storage will be preferred for various reasons – not least because of the public awareness.

The selection of transport option for offshore storage is illustrated in Figure 8, where there is a rather distinct trade-off between capacity and distance. High capacities are prone to favour piping, whereas low capacities favour tank transport on board ships.

¹⁴ (<http://www.anthonyveder.nl/fleet/ccarbonic.html>, 2004)

¹⁵ I.e. the former Norsk Hydro Agri Company. (www.hydro.com, 2004, <http://www.larvik-shipping.no/>, 2004)

¹⁶ Important conventions hereto are 1) the UN Framework on the Law of Sea (UNCLOS), 2) the London convention, 3) the conventions on Environmental impact assessment in trans-boundary context (ESPOO Convention) 4) Oslo-Paris Convention (OSPAR), 5) the Integrated Pollution Prevention and Control directive (IPPC/EC), 6) Council directive 2000/60/EC establishing a water framework of Community action in the field of water policy, 7) Waste directive /EC 75/442/EEC).

Figure 8: Transport means for CO₂ ex plant for offshore storage divided by transport capacity versus distance.

1.6 Preparing new sources for carbon dioxide capture

The IEA-GHG R&D Programme (IEA 2004) has presented an overview of the industrial point sources for CO₂ around the world. In order to evaluate the possibilities of CO₂ capture in the foreseeable future it is required to assess the present sources for CO₂ as well as the planned ones. One should also keep in mind the importance of the economic impact of future CO₂ capture, especially in terms of options like enhanced oil and gas recovery (EOR and EGR).

In order for future CO₂ sources to be deemed viable for CO₂ capture, different evaluation criteria have to be applied. One of these criteria is how attractive CCS may become on economic terms reckoned per tonne of CO₂, which eventually is a direct consequence of the type and location of the CO₂ source at hand. (Refer Chapter 6 for details concerning capture costs.) In the consideration of future sources the logistics pertaining to the transport of the CO₂ from source to storage site will generally become decisive. (Refer Chapter 12 for details on transport costs.)

The IEA-GHG R&D Programme (IEA 2004) also provided a global database that contains a global overview of industrial GHG emission nodes especially from power plants, oil refineries, gas processing plants and major industrial sources such as ammonia, hydrogen, ethylene, ethylene oxide, cement, iron & steel plants. This database may be found useful for the prediction of future CO₂ emissions at existing sites and also for the assessment of possible or planned new sites derived on the basis of expected growth indicator per sector.

A recent NFR report (SINTEF PR et al. 2004) presents an overview of point sources for CO₂ that are larger than 50 000 tpa originating from facilities that operate on the Norwegian continental shelf. Obviously the offshore power systems are numerous, as most installations have to rely on autonomous power supply. The report also includes shore-based plants located less than 100 km from the North Sea rim. Figure 9 identifies the CO₂ sources around the North Sea, whereas Figure 10 depicts the CO₂ sources and the oil fields that are potentially of interest for EOR.

Figure 9: Schematic of CO₂ sources around the North Sea basin (Sundset 2003).

Figure 10: Potential CO₂ for EOR. According to Statoil there are several sites that have the potential for using CO₂ for enhanced oil recovery in the North Sea and further north. (Sundset 2003).

There is some difference between the Nordic countries in terms of the characteristics and the present size of the CO₂ sources. Most likely these differences are not subjected to change in the foreseeable future. Hence, by year 2004, 29% of the total Norwegian CO₂ emissions were attributed to the oil and gas sector whereof 89% refers to stationary sources off shore (OED 2006). In Denmark, however, most of the CO₂ emissions stem from coal-fired power plants. In addition Denmark has a widespread infrastructure with relatively small combined heat and power plants running on natural gas. In Finland the greatest CO₂ emitting plants are oil refineries, coal- and-gas-fired power plants and steel works. And, in Sweden, only 8.7% of the Swedish power is generated from fossil fuels, and the country does not have many coal-fired power plants left (if any) (EU 2006). Furthermore, as shown in Figure 11 Sweden is keeping a leading position in the use of energy from biomass and waste jointly with Finland, whereas Norway and Denmark keep a rather low profile in this particular endeavour.

Figure 11: The use of energy from biomass and waste in the four Nordic countries as per 2003 according to current data from Eurostat (Source: Eurostat, EU 2006).

1.7 Relationship between size of carbon dioxide sources and capture cost

The IPCC special report on “Carbon dioxide capture and storage” (IPCC 2005) presents an overview of factors that affect the CO₂ capture cost. Among the main findings a mention could be given as follows:

- Technology must be defined before firm cost assessments can be made. The reason is that the cost may vary widely with the capture

approach and technology as well as the kind of power system (or process) that is subjected to carbon capture;

- A system boundary must be drawn,
- The time frame and maturity of technology must be set;
- The presumptions to be pre-defined or adjusted as appropriate.

Figure 12 presents the cost of electricity (excluding transport and storage costs) versus the CO₂ emission factor (reckoned in tonnes of CO₂ emitted per MWh produced power) based on current technology. It is obvious that the cost of electricity is going to increase if capture is introduced in the supply chain, but the chart also indicates that a difference in costs between power generation from natural gas and coal may persist. This may, however, change to the opposite on a longer term for more reasons; firstly because coal is more abundant and widespread around the world, secondly, because of the impact of economy of scale, and thirdly, because the demand for natural gas will increase, thus, pushing the price comparatively high. Should CCS become viable on technical and economic terms it is likely to believe that for instance pre-combustion capture via coal gasification may compare better with natural gas than how it appears in Figure 12.

Figure 12: Cost of electricity compared with the CO₂ emission rate for different reference capture plants based on current technology (IPCC 2005).

When considering capture cost one should keep in mind that the technical attractiveness may depend on the fuel. For instance will the flue gas from coal-fired power plants contain typically 12-14 vol%, whereas the flue gas from natural gas-fired power plants contains only 3-4 vol %. On the other hand may the flue gas from cement kilns and iron and steel works contain as much as 20-30 vol% CO₂. Hence, the unit cost of capturing CO₂ per tonne removed from a flue gas must be lower with coal than with natural gas.

The economic advantages for capturing CO₂ from coal-fired power plants post combustion compared with natural gas power plants may be summarized as follows (ref. SINTEF PR et al. 2004):

- CO₂ content of the flue gas from a coal-fired power plant: 3-4 times higher than with natural gas;
- Plant-efficiency of modern coal-fired plant: Typically 45% (LHV);
- Plant-efficiency of modern natural gas-fired plant: 57% (LHV and combined cycle, state of the art);
- CO₂ capture rate: 90 % with natural gas, 80% with coal.

Hence,

- The volume of CO₂ in a flue gas from coal/natural gas is typically 2/1;
- Investment cost for infrastructure is higher with coal per unit CO₂ captured.

In addition:

- The oxygen content in the flue gas with natural gas (combined cycle) increases the heat required for amine regeneration. And, likewise, the solvent is prone to decay faster. Hence, the operating cost per tonne CO₂ captured is prone to become higher with natural gas.

The main CCS cost will be attributed to capture and compression of the CO₂. The CO₂ transport cost, however, will depend on several factors, such as volume, distance, soil type, terrain, density of population, and should be kept in mind when considering location of storage versus capture.

In order for CCS to become viable, it is necessary to have a substantial amount of CO₂ at hand. The relation between investment cost per tonne CO₂ versus the size and availability of the CO₂ source is presented in Figure 13, which shows that the relative investment cost is prone to increase substantially when the amount of CO₂ becomes lower than a critical mass – in this case around 750 tonnes per year. This cost should, hence, be considered indicative, as it does not include distance and other decisive elements.

Figure 13: Relative investment cost per tonne CO₂ of plants with capture versus plants without capture (ordinate) as function of amount of CO₂ available in 1000 tpa.

1.8 Public acceptance of geological carbon dioxide storage

Based on experience with other energy and non-energy technologies, public acceptance is widely recognized as crucial to the success of a CCS as a climate policy measure (e.g., Friedmann and Homer-Dixon 2004; Gielen and Podkanski 2004:189). Public acceptance involves the opinions and perceptions of the public at large as well as the views of key stakeholder groups such as environmental non-governmental organizations (ENGOS) and affected business sectors. Below, we outline what is presently known about public opinion and stakeholder attitudes, and we point out the most important issues related to public acceptance of geological CO₂ storage.

1.8.1 Public opinion

There is no direct evidence available regarding the views on CCS held by the general public in the Nordic countries. Evidence from other countries suggests that very few are familiar with CCS. For instance, in a representative sample of the U.S. population polled in 2003, only 3-4 percent said they had heard or read about CCS in the past year. In comparison, more than 50 % said they had heard or read about several other energy technologies such as solar energy and fuel-efficient cars. Asked whether “carbon capture and storage” or “carbon storage” could solve various environmental problems a large majority were unable to answer, and more people pointed to smog than global warming (Curry et al. 2004; Curry 2004). In a survey asking the same questions to a sample of the UK

public in 2005, CCS appeared to be only slightly more familiar. Just 2-5 percent said they had heard or read about CCS in the last year. A majority was unable to say whether or not CCS could solve various environmental problems even here, but there were clearly more people who thought that CCS could reduce global warming than any other environmental problem (Curry et al. 2005). These studies also show that while the US and UK publics are enthusiastic about energy efficiency, various renewable energy sources, as well as terrestrial sequestration (forests) as climate policy measures, they are much more skeptical about CCS.

It is likely that the public's familiarity with CCS is limited even in the Nordic countries. In Norway, where CCS has been debated for a number of years, familiarity is likely to be higher than in the other Nordic countries. For the same reason, more stakeholder groups such as NGOs or business actors have explicit policy positions in Norway. In the Norwegian case, political leaders including the previous center-right coalition government as well as the center-left coalition presently in office have given Norway's CCS strategy a fairly high political profile. While there has been some public debate on the merits of CCS and the specifics of government policy in this area, there is little sign of broad-based public opposition to CCS as such in the Norwegian case.

1.8.2 Environmental movement attitudes

The environmental movement could potentially play a key role in shaping public opinion on CCS, mobilizing the public for or against CCS projects and influencing the positions of governments. Such a role is facilitated by the largely unformed public opinion on this issue, and the high level of trust enjoyed by ENGOs in the Nordic countries. The potential for ENGO influence is illustrated by the environmental movement's rather effective opposition to deep-ocean CO₂ storage experiments in the U.S. and Norway (de Figueiredo 2002; Haugneland 2002). In these experiments researchers proposed to experimentally dissolve CO₂ in deep layers of seawater rather than below the seabed.

Internationally, ENGOs have mostly taken a sceptical attitude towards CCS (Solsbery et al. 2004:118-122, see also von Goerne 2004, and documentation from workshops held by the ENGO coalition Climate Action Network Europe available at www.climnet.org/CTAP). The ENGOs' main worry is the climate and energy policy consequences of a CCS strategy. Many ENGOs point to the risk that storage sites might leak and release large amounts of greenhouse gases to the atmosphere, and that public funding for research, development and demonstration (RD&D) of CCS technologies as well as incentives for their deployment might replace support for renewable energy and energy conservation. Some argue that if CO₂ is used for enhanced oil or gas recovery before storage, the increased supply of fossil fuels will cancel out the climate

benefits of CCS. Finally, several ENGOs are concerned that CCS will enable prolonged reliance on fossil fuels, and point to non-climate damages from fossil fuel extraction such as oil spills, or landscape alteration and toxic waste from coal mining.

The major international groups, Greenpeace, WWF and Friends of the Earth International (FoEI) have expressed strong scepticism towards a CCS strategy. Greenpeace holds the strongest negative views. There are some indications that important ENGOs active in countries where CCS is seriously considered as a policy option are warming to the idea. Friends of the Earth's UK branch recently expressed cautious support for a government-supported CCS strategy (FoE 2005). Two Norwegian groups campaign actively to promote a CCS strategy: The Bellona Foundation and Zero Emissions Resource Organization (ZERO). FoEI's two Norwegian member organizations, *Naturvernforbundet* and *Natur og Ungdom*, have recently expressed positive views towards CCS, while stressing that this should only be a supplement to renewable energy sources and efficiency. Other Norwegian groups such as The Future In Our Hands (FIVH) and branches of WWF and Greenpeace are still distinctly sceptical.

As one might expect, a brief survey of their web pages suggests that ENGOs in other Nordic countries have given CCS far less attention than their Norwegian counterparts. Before the Climate Convention meeting in Montreal in late 2005 (COP11), however, the Danish group NOAH (affiliated with FoEI) specifically opposed CCS projects under Kyoto Protocol's Clean Development Mechanism (NOAH 2005). It is by no means given that environmental movement organizations in Sweden, Denmark and Finland will be as open to CCS as some of their Norwegian counterparts when they come to consider the issue in more detail. The political attractiveness of CCS is particularly distinct in Norway with its energy-intensive industrial structure, inviting pragmatic ENGOs seeking political results to accept CCS solutions. The most sceptical international group, Greenpeace, also has a much weaker position in Norway than in Sweden, Finland or Denmark: Only about 3% of Greenpeace Nordic's registered supporters are Norwegians (Greenpeace 2005).

1.8.3 Business attitudes

Several major companies in the Nordic energy industry are actively involved in CCS projects (e.g. Elsam, Vattenfall, Statoil, Norsk Hydro, AkerKværner). Broadly speaking, private business is perhaps the group of stakeholders least likely to have objections to geological CO₂ storage as such. Given emissions regulation, industry may favour CCS if this is perceived as less expensive than other mitigation options and/or potentially opening up new future markets for technology delivery. Industry can be expected to seek government support or incentives for deployment, as illustrated by recent CCS initiatives by Shell and Statoil in Nor-

way and by BP in Britain. However, regulations making CO₂ capture obligatory would by all likelihood be opposed by regulated sectors and might motivate business actors to question the benefits of CCS more generally.

Storage on or near land increases the likelihood of conflicts of interest with existing business activities related to potential leakage, compared to offshore sites. Another potential source of conflict is the distribution of public RD&D funding and incentives for deployment between fossil power with CCS on the one hand, and other sources of low-carbon energy (renewable, nuclear, or conservation) on the other.

1.8.4 Key issues

Three classes of concerns are particularly relevant to public acceptance of geological storage. The first relates to human health, safety and groundwater supply and pertains mainly to storage on land. The second relates to consequences for terrestrial or marine ecosystems due to the risk of leakage. The third concerns the energy and climate policy aspects of a CCS strategy.

As a general observation, the public is likely to be a lot more worried about storage in geological formations under inhabited land areas than about storage under the seabed. This is because on land, health and safety concerns for people are added to the list of potential problems, along with contamination of freshwater aquifer resources. In case of accidental and abrupt release of large amounts of CO₂, people present might suffocate. Depending on local geological conditions, contamination of groundwater and induced seismic activity (small earthquakes) are more likely, but less dramatic consequences of CO₂ storage (IPCC 2005). Experience with natural gas storage in geological structures suggests that these issues may be manageable, but likely to cause “NIMBY” (Not In My Back Yard) reactions. Experience with opposition to natural gas storage in aquifers on land has led some Danish officials to expect strong reactions if similar projects for CO₂ storage were proposed (Solsbery et al. 2004:74). Indication of worries about local effects is also found in an inquiry about CO₂ storage among 112 residents in a part of the Netherlands subject to small earthquakes induced by underground natural gas storage (Huijts 2003).

Whether ecosystem effects will be a major concern for public opinion is perhaps less predictable, and will to a large degree depend on the positions adopted by experts and organized interests such as ENGOs. In the near-term future, the discussions under the OSPAR regime is the most likely focal point for these issues, and the geological storage issue in OSPAR has not generated a lot of public attention this far. What is certain to generate debate around any CCS strategy is its climate and energy policy consequences. Relevant aspects of this discussion are mentioned in connection with the positions of ENGOs above.

Part 2: CCS in a Nordic perspective

2.1 Comparing the Nordic Countries

The four Nordic countries subjected to this study are well-developed countries having a high prosperity level, enjoy a stable growth as can be concluded from Figure 14. The high GDP (gross domestic product) per capita in Norway is mainly due to the revenues from oil and gas.

Figure 14: Economic growth versus GDP per capita as per year 2004 of the Nordic countries less Iceland. The bubble size refers to the population by country. (Data source: CIA database, www.cia.gov). Note that neither of the axes starts at zero.

The energy intensity is an expression of how efficient energy is used, and thus how the energy use is prone to affects a nation's economy. Hence, the energy intensity of the Nordic countries, as shown in Figure 15, suggests that the use of energy in the Nordic societies is gradually improving. Figure 15 also tells that the cost of converting energy into currency is higher in Finland and Sweden than in Norway and Denmark. Although numerous factors influence the energy intensity, it is likely to believe that the climatic conditions and the standard of living are fairly similar within the four nations. It is believed, though, that a main difference owes to structural discrepancy in the industry and the power sector among the countries.

SINTEF Energy Research / Jens Hetland, 2006

Figure 15: Energy intensity of the economy of the Nordic countries in terms of grams of oil equivalents (goe) used per Euro according to Eurostat data (March 2006). (Note that neither of the axes starts at zero.)

Among the 27 Western-European countries, as shown in Table 2, Denmark is ranked number 12, Sweden number 13, Finland number 14 and Norway number 16 in terms of total CO₂ emissions according to available 2003 data (EIA 2005). The foregoing year (2002) the situation was somewhat different, as Sweden was then ranked number 12, Finland number 13, Denmark number 14, whereas the position of Norway was the same (16). This tells that the former countries emit almost the same amount of CO₂ from fossil fuels, while the Norwegian emissions are somewhat less (23.2% lower than Denmark in total amounts). Taking into account the relatively small population in the Nordic countries, however, the per capita CO₂ emission index becomes rather high.

As the main driver for CO₂ emissions is the consumption of fossil fuels, the recent history of the consumption may be helpful in explaining the rate of change. As depicted in Figure 16 Sweden and Denmark have managed to reduce their total emissions – particularly during the latest decade. Finland remains almost at status quo, whereas Norway has been increasing its emissions quite significantly year on year.

Table 2: Ranking the European CO₂ emission by country by year 2003. Emissions are reckoned in Mtpa CO₂ per country. (Data based on EIA 2005)

Rank	Region/Country	2002	2003
1	Germany	854,3	842,0
2	United Kingdom	558,2	564,6
3	Italy	446,6	465,5
4	France	403,4	409,2
5	Spain	337,6	339,7
6	Netherlands	256,0	259,6
7	Turkey	192,4	204,2
8	Belgium	140,7	140,9
9	Greece	101,5	104,3
10	Austria	67,8	72,4
11	Portugal	65,4	62,1
12	Denmark	52,3	58,6
13	Sweden	54,4	55,7
14	Finland	54,1	54,2
15	Serbia and Montenegro (Yugoslavia)	46,3	50,6
16	Norway	45,7	45,0
17	Switzerland	44,0	43,0
18	Ireland	42,0	40,6
19	Croatia	21,1	22,2
20	Slovenia	16,4	16,6
21	Bosnia and Herzegovina	15,6	14,6
22	Luxembourg	10,4	10,9
23	Macedonia	8,0	8,5
24	Gibraltar	4,0	4,1
25	Iceland	3,1	3,0
26	Malta	2,9	2,9
27	Faroe Islands	0,7	0,7
	Western Europe	3845,0	3895,8

The severity of the current situation can be summarised by Table 3, in which the current status of greenhouse gas emissions of the four Nordic countries are listed and compared with the agreed emission targets. The table shows that Denmark, Finland and Norway are substantially exceeding their agreed targets, while Sweden appears to be well below its emission target. Hence, substantial efforts are required and awaited over the coming years in the three former countries in order to fulfil their obligations.

Figure 16: CO₂ emission in the Nordic countries originating from the use of fossil fuels in total emission number (million tonnes per annum) versus year. The thin lines are actual consumption, the bold lines are weighted regression throughout the reporting period (1980-2003). Source of data: *The International Energy Annual 2003 of the USE DoE*¹ (Source: EIA 2005). (Note that neither of the axes start at zero.)

Table 3: Greenhouse gas emissions per country by baseline (1990), target (2008-2012), status per 2003 and deviation from the agreed targeted emission (Sources: Enviro Solutions, SSB 2006 and EIA 2005).

	GHG emissions, baseline 1990 Mtpa	emissions, baseline 2008-2012 Mtpa	level	GHG emissions, 2003 Mtpa	emission year	CO ₂ emission, year 2003 Mtpa	Deviation in GHG emissions from target %
Denmark	69.6	55.0		74.0		58.6	+34.6
Finland	70.4	70.4		85.5		54.2	+21.5
Norway	50	50.6		54.5		45.0	+7.7
Sweden	72.3	75.2		70.6		55.7	-6.1

Note: Mtpa denotes million of tonnes per annum

The electricity production in the Nordic regions can be summarised as follows from Table 4:

Table 4: Total electricity generation in TWh by primary energy source and net exports/imports and domestic consumption by year 2003 (Sources: EU 2006; NVE Statistikk 2006)

	<i>Denmark</i>	<i>Finland</i>	<i>Norway</i>	<i>Sweden</i>
Total el-production	46.2	84.2	107.3	135.6
Conventional thermal	37.5	42.1	0.43	8.7
- Coal	25.3	26.2	0.04	2.7
- Oil	2.3	0.9	-	3.9
- Gas	9.8	14.5	0.39	1.8
- Other	-	0.5	-	0.3
Nuclear	-	22.7	-	67.4
Pumped storage	-	-	0.863	0.1
RESe	8.7	19.4	106.83	59.4
- Hydro	0.021	9.591	106.101	53.215
- Biomass	3.163	9.700	0.470	5.598
- Wind	5.561	0.093	0.260	0.631
- Solar	-	-	-	-
- Geothermal	-	-	-	-
Net exports	8.6	-	-	-
Net imports	-	4.9	7.9	12.8

2.1.1 Carbon tax

In the early 1990-ies the Nordic countries implemented a CO₂ tax (or just carbon tax) that works slightly different from country to country (Andersen).

Finland was the first country to introduce a carbon tax in 1990. The tax was set rather low at the outset, however, without exemptions (except for peat). Later the system was simplified in the sense that the taxation of electricity was per kWh rather than by differentiating according to the released CO₂ during generation.

Sweden introduced a tax in 1991 at a relatively high rate levied similarly on industry and households. In 1993 the industrial carbon tax was reduced to 25% of that of the households because of specific concerns regarding the competitive edge of the Swedish industry. Three years later the industrial tax was increased to 50% of the household level. Swedish studies tell that the tax had a significant impact on emissions, although the tax alone cannot explain the reduction of CO₂ in Sweden that started with a change in policy in the mid 1970-ies – as a result of the first oil crisis that resulted from the Yom Kippur war.

Norway introduced a carbon tax in 1991 at a high nominal tax rate, but many industries were exempted and the tax rate per tonne of CO₂ emitted varied. Coal, coke, mainland gas and fuels for ship and air transport were exempted. Later the tax system was expanded to include

coal/coke and domestic air transport, and some tax rates have been adjusted. The tax now applies to most industries, including the oil and gas sector, covering about 64% of Norway's CO₂ emissions. Exemption is given to energy-intensive industries, non-domestic aviation and to domestic sea freight (Miljøverndepartementet 2002).

Denmark introduced a carbon tax in 1993, and exempted its electricity export. Later studies show that almost all the companies that were affected by the tax reduced their energy demand by more than 20%, however, without negative impacts on the employment.

In brief this coarse review tells that the carbon tax may have a slightly different impact in the four countries, and it may be useful when comparing the four countries.

2.1.2 Statistics used for CO₂ emissions from fossil fuels

The International Energy Annual 2003¹⁷ (EIA 2005) includes statistics for the total world carbon dioxide emissions per region and country originating from the consumption of petroleum, natural gas, and coal, and the flaring of natural gas. As this use is most relevant in terms of CO₂ capture, said statistics are used for the assessment of the Nordic countries per se and vis-à-vis the world.

One of the results of the IEA-GHG R&D programme is a database of industrial CO₂ emissions around the world (IEA 2004). Applied to the Western European OECD countries 2069 entries are found, comprising:

- Ammonia plants
- Cement plants
- Ethylene plants
- Ethylene oxide production
- Gas processing complexes
- Hydrogen production
- Iron and steel works
- Power plants
- Refineries

The United Kingdom and the Rotterdam area are two of the most important areas when it comes to concentration of large CO₂ emission sites in Western Europe. This is shown in chapter 7, where an overview was given of the main CO₂ sources in the proximity of the North Sea region, together with possible EOR fields. However, in the context of this report with its Nordic perspective, an overview is given of the major stationary sources of CO₂ in Denmark, Finland, Norway and Sweden, such as the

¹⁷ Energy Information Administration, EIA, US DoW, Tables of International Energy Annual 2003 were last updated by 11 July 2005. Refer also: <http://www.eia.doe.gov/iea/overview.html>

offshore sector, power plants, oil refineries and energy intensive industries.

2.2 Facts and aspects of CO₂ emission in the Nordic countries

2.2.1 Denmark

Facts that relate Denmark to CO₂ owing to its use of fossil fuels:

- Danish population: 5.416 million (2004);
- Denmark is the 12th largest emitter of CO₂ in Western Europe (Table 3) and number 23 in the world in total CO₂ emissions, and number 6 per capita (2003) (EIA 2005);
- Denmark is responsible for 1.5 % of the total Western European CO₂ emissions, and accounts for 0.23 % of the global CO₂ emissions (2003);
- According to the 'EU burden sharing agreement' Denmark has agreed to reduce its greenhouse gas emissions by 21 % compared with the baseline of 1990 (i.e. 69.6 Mtpa GHG);
- By year 2003 the total Danish GHG emissions were 6.3% higher than the baseline, thus exceeding the target by 34.6%;
- Denmark is further relying on energy efficiency improvements, additional renewable energy and possible fuel switch from coal to natural gas at power plants;
- A large portion of its electricity is generated from wind power;
- Nuclear power is not considered a likely option in Denmark.

Denmark has one of the most efficient multi-fuel power plants in the world (Avedøre, Copenhagen), which in addition to coal and natural gas also makes use of biomass (basically straw) in order to suppress the CO₂ emission. The net capacity of Avedøre 2 is 435 MWe. The power may be boosted to 585 MWe when adding a peak capacity offered by gas turbines.

Figure 17: The Avedøre power plant at Copenhagen, Denmark.

Furthermore, a flue-gas cleaning pilot attached to a Danish coal-fired power plant at Esbjerg (Denmark) was inaugurated in March 2006 for the purpose of cleaning a slip-stream – post combustion – corresponding to 1 tonne CO₂ per hour. The operator of the plant is the Danish Elsam. Reportedly, the CO₂ capture cost of this cleaning unit is in the range 20-25 €/tonne including capital expenditures (ENS 2006).

2.2.2 Finland

Facts that relate Finland to CO₂ owing to its use of fossil fuels:

- Finnish population: 5.261 million (2004);
- Finland is the 14th largest emitter of CO₂ in Western Europe (Table 3) and number 33 in the world in total amounts, and ranked number 8 per capita (2003) (EIA 2005);
- Finland is responsible for 1.4 % of the total Western-European CO₂ emissions, and accounts for 0.22 % of the global CO₂ emissions (2003);
- According to the 'EU burden sharing agreement' Finland has agreed to limit its greenhouse gas emissions at the baseline level of 1990 (i.e. 70.4 Mtpa GHG);
- By year 2003 the total Finnish GHG emissions were exceeding the target by 21.5%;
- By 2003 the total GHG emissions were 21.5% above the agreed target;

- Finland is relying on nuclear power, energy efficiency improvements, large-scale utilisation of renewable energy, natural gas from Russia and coal power generation;
- Finland is currently extending its nuclear power capacity by building its fifth reactor at Olkiluoto.

Oil refineries, coal-fired power plants and steel works are the largest sources for CO₂ emission in Finland (Koljonen 2002). In 2004, the pulp and paper industry accounted for about 15% of the CO₂ emissions resulting from the use of fossil fuels in Finland (Teir 2004). However, owing to the substantial use of bio-energy, the total CO₂ emissions in this sector have decreased considerably throughout the last decade.

The most significant point sources of CO₂ appear on the non-extensive map by source point in Figure 18 and by sector in Figure 19. Significant point sources may be omitted on the map, due to insufficient reporting, which may be the case especially for the industrial sector. The data are mainly collected from annual reports or environmental reports issued by companies.

Figure 18: Finnish point sources for CO₂ by geographical location and size. (Koljonen 2002)

Figure 19: The largest CO₂ emitting point sources in Finland (Koljonen 2002).

In Figure 19 the CO₂ emissions from selected pulp and paper plants in Finland are depicted according to Tuulia Raiski (M.Sc thesis at HUT 2004).

2.2.3 Norway

Facts that relate Norway to CO₂ owing to its use of fossil fuels:

- Norwegian population: 4.622 million (2004);
- Norway is the 16th largest emitter of CO₂ in Western-Europe (Table 3) and number 39 in the world in total and number 11 per capita (2003) (EIA 2005);
- Norway is responsible for 1.15 % of the total Western-European CO₂ emissions originating from fossil fuel, and accounts for 0.18 % of the global CO₂ emissions (2003)
- According to its Kyoto commitments Norway has agreed to limit its greenhouse gas emissions at 1 % above the 1990 level (50.6 Mtpa GHG, whereof 35 Mtpa CO₂);
- By year 2004 the GHG emissions were surpassed by about 8%, whereas the CO₂ emission per se had increased by 26% over the 1990 level (SSB 2006), whereas the remaining five greenhouse gasses were reduced by 72%;
- Norway is one of the most independent nations in the world in terms of primary energy supply due to its hydropower production and offshore oil and gas reserves. Nevertheless, as most of the oil and gas are exported, Norway has to rely on additional power import as well as energy efficiency improvements, and some renewable energy;

- New gas-fired power plants have since long been postponed due to the Kyoto commitments, thus, awaiting new CCS technology to emerge;
- Furthermore, nuclear power is no issue in Norway.

In contrast to any industrialised country anywhere in the world, the Norwegian power sector - owing to the predominance of hydroelectric power - does practically not contribute to the emission of CO₂. The current hydropower production is 118 TWh (average year), which is 99.4% of the national power generation. The low and high production may, however, reach from about 90 to 145 TWh per annum depending on the precipitation. Nevertheless, due to its position as a major exporter of oil and gas, the Norwegian emissions are ranked high despite the limited population of the country. In 2004 the oil and gas industry accounted for about 29 % of the national CO₂ according to OED (OED 2006), and about 22% of the greenhouse gases according to the Carbon Sequestration Leadership Forum (CSLF 2006).

In May 2002 Norway ratified the Kyoto Protocol as an "Annex I state", and thereby committed itself to limit its net greenhouse gas emissions to 1% above the 1990 level by 2008-2012.

Figure 20: Map showing the larger point-sources for CO₂ in Norway and its continental shelf. (Høst and Bøe 2001)

Figure 21: Norwegian point sources for CO₂ (GESTCO project).

The major sources for CO₂ from Norwegian industries and offshore oil and gas production are identified as (NFR 2004):

- The Kårstø industrial complex at Haugesund. The gas processing plant emits about 1.2 Mt CO₂ annually from gas turbines and boilers. The volume may, however, increase due to additional deliveries to be taken from new gas fields.

- The Mongstad refinery and industrial complex at Bergen is the largest CO₂ point source in Norway. The cracker at the oil refinery and associated steam boilers emit 1.8 Mt CO₂ annually. If a combined heat and power plant is built 2.75 Mtpa CO₂ could be subjected to CCS.
- The Tjeldbergodden methanol and chemical complex in the municipality Aure. The methanol plant presently emits 0.35 Mt CO₂ annually. If the planned methanol production is expanded in combination with a gas-fired power plant this volume will increase to 3.0 Mtpa CO₂.
- Grenland and Herøya industrial complex, at Porsgrunn. The ammonia plant at Herøya produces 0.35 Mt CO₂ annually, but today the CO₂ is shipped to the continental Europe and mainly used by the food industry. Other point sources in this area, such as the cement plant in Brevik, emit around 1 Mt CO₂ annually.
- Snøhvit LNG plant, Melkøya, Hammerfest (scheduled to go on stream by 2007). The plant will include CO₂ capture from the produced gas. The CO₂ content of gas from the Snøhvit reservoir must be reduced before LNG is produced at the Melkøya plant. About 0.7 Mt CO₂ annually is planned injected in a reservoir underneath the Snøhvit field. In addition 0.8 Mt CO₂ is produced by gas turbines at Melkøya.

Offshore oil and gas:

- The Sleipner CO₂ project has been on stream since 1996 and about 1 Mtpa CO₂ has been separated from the CO₂-rich gas produced at the Sleipner platform and injected into the Utsira aquifer formation, which is deemed well-suited for long-term storage. The CO₂ production will be reduced to 0.8 Mtpa in 2007-8 and further to about 0.15 Mt by 2018. The project (designated SACS) is operated by Statoil.

Further offshore point sources are shown on maps in Figure 20 and Figure 21. These sources are mainly due to flaring and power generation on board offshore oil and gas installations in Norwegian waters. The separation of CO₂ from the produced natural gas like Snøhvit and Sleipner (above) are furthermore considered for novel plants, such as the Ormen Lange gas terminal at Aukra.

In March 2006 Statoil and Shell jointly decided to pursue a new 860 MWe plant at Tjeldbergodden fully equipped with capture technology from the outset.

Figure 22: CO₂ emission (in tpa) from Norwegian industrial players according to Bellona (Source: Jakobsen et al. 2005).

Other significant CO₂ sources

As depicted in Figure 20 and Figure 21 there are relatively few major point sources for CO₂ in Norway. Some sources stem from oil and gas production and in addition there are a few major industrial sources. Figure 22 lists the potential CO₂ emission from Norwegian industries and energy.

If realised, the planned gas-fired power plants will become major new CO₂ point sources as shown in Figure 24. For instance will the planned 420 MWe gas-fired power plant at Kårstø produce 1.2 Mtpa CO₂ and the planned gas-fired power plant at Skogn 2.2 Mtpa CO₂. More gas-fired power plants are planned at Mongstad (an additional 0.95 Mtpa CO₂), Hammerfest Energi (0.3 Mtpa CO₂), and Skagerak Energi in Grenland (1.1 – 2.8 Mt CO₂). And the gas-fired power plant in Elnesvågen at Molde will be similar to the Kårstø plant (420 MWe). This plant is planned to employ carbon capture wherefrom the CO₂ will be used partly in the surrounding industry and partly for EOR/EGR. By June 2005 it was jointly decided by the owners, Statkraft AS (50%) and Norsk Hydro ASA (50%), to build a 420 MWe power plant at Kårstø that will be capable of generating 3.5 TWh electric energy per year. According to a news bulletin¹⁸ the plant will have a price tag of 2000 MNOK, and it will be the first plant ever in its size to employ NO_x cleaning. At rated production the plant will release 1.2 Mtpa CO₂. According to the owners, provi-

¹⁸ Naturkraft bygger gasskraftverk på Kårstø, 24 June, 2005 (http://www.naturkraft.no/default.asp?V_LANG_ID=0&RND=1)

sions will be made for post-combustion exhaust gas cleaning at a later stage, provided, however, that such carbon capture technologies become viable on technical and economic terms.

Table 5: Stationary emission of CO₂ in Norway with impact on a possible CO₂ value chain (Source: Jakobsen et al. 2005).

Connected stationary CO ₂ emission sources	Gross CO ₂ emissions Tonnes	CO ₂ production with 85% capture Tonnes
CO₂ sources for region Norwegian Ocean		
Melkøya NGCC	625 000	531 250
Hammerfest Energi NGCC	290 698	247 093
Methanol factory	550 000	467 500
TBO NGCC	2 500 000	2 125 000
Skogn NGCC	2 325 581	1 976 744
Total	5 375 581	4 569 244
CO₂ sources for region North Sea		
Skagerak Energi NGCC	2 906 977	2 470 930
Borealis	59 000	50 150
Hydro Polymers, Rafnes	100 000	85 000
Noretyl, Rafnes	525 000	446 250
Norcem Kjølsvik	420 432	357 367
Norcem Brevik	951 971	809 175
Kårstø gas processing facility	1 650 000	1 402 500
Kårstø NGCC	1 250 000	1 062 500
Kollsnes gas facility	56 000	47 600
Mongstad Refinery	1 660 000	1 411 000
Mongstad NGCC	813 953	691 860
Sleipner CO ₂ production	1 000 000	1 000 000
Total	11 393 333	8 834 333
CO₂ production based on existing and planned projects	16 768 915	13 403 577
Wanted additional projects		
Increase capacity of TBO NGCC to 2GW	3 313 953	2 816 860
Increase capacity of Mongstad NGCC to 2GW	3 313 953	2 816 860
Building EuropePower NGCC - 5GW	14 534 884	12 354 651
Total additional CO₂	21 162 791	17 988 372
Total potential CO₂ production to NCS	37 931 705	31 391 950
Potential CO ₂ production to Draugen CO ₂ deposit	8 689 535	7 386 105
Potential CO ₂ production to Heimdal CO ₂ deposit	29 242 170	24 005 845

Source: SFT, Bellona 2005

Figure 23: Layout of the gas-fired power plant under construction at Kårstø (picture retrieved from a news bulletin, NaturKraft).

Hence, the existing and planned point sources for CO₂ in Norway are summarized in Figure 24.

Figure 24: Planned point sources of CO₂. Existing emissions from the refinery at Mongstad is marked blue.

The emissions clearly illustrate the amounts of CO₂ that is and may become available in Norway in the near future. Interesting is, however, that these sources may have a direct bearing on the future oil and gas production, as the CO₂ may be used commercially for enhanced recovery of oil and gas from the Norwegian continental shelf. A main concern, however, is that each of the planned power plants will not provide enough CO₂ for any of the possible Norwegian EOR sites.

2.2.4 Sweden

Facts that relate Sweden to CO₂ owing to its use of fossil fuels:

- Swedish population: 9.048 million (2004);
- Sweden is the 13th largest emitter of CO₂ in Western Europe (Table 3) and number 73 in the world in total amounts, and number 20 per capita (2003) (EIA 2005);
- Sweden is responsible for 1.4 % of the total Western-European CO₂ emissions originating from fossil fuels, and accounts for 0.22 % of the global CO₂ emissions (2003);
- According to the internal EU burden sharing agreement Sweden has agreed to limit its greenhouse gas emissions at a level that is 4 % above baseline (1990, which was 72.3 Mtpa GHG);
- By year 2003 Sweden's GHG emissions were 2.4% lower than baseline;
- Sweden is relying on energy efficiency improvements and large-scale utilisation of renewable energy and waste. Some import of natural gas mainly via Denmark;
- In 1980 Sweden decided in a referendum to phase out their 11 nuclear reactors, but has so far only closed down one (Barsebäck). Meanwhile the capacity of the remaining reactors have more than compensated for the abandoned reactor, and the 10 operating reactors generate almost 50% of the country's electricity demand via the 8938 MWe (aggregated) nuclear generating capacity. Capacity enhancement of Forsmark nuclear power plant is being discussed (May 2006).

According to EU Statistics (EU 2006) and Briefing paper 39 on Nuclear Power in Sweden of February 2006¹⁹ (Nuclear Sweden 2006) the Swedish power balance can be explained by Table 6, which shows that less than 10% of the power sector is fuelled by fossil fuels.

Table 6: The electric energy balance in Sweden by year 2003 and 2005. The 2003 figures are in compliance with Table 4 (EU 2006), whereas the 2005 figures refer to Briefing Paper 39 on Nuclear Power, Feb 2006¹⁹ (Nuclear Sweden 2006)

	2003	2005
Nuclear power	43.8%	45%
Fossil fuels	6.4%	8%
Hydropower	39.2%	47%
Imports	9.4%	
Exports		4%

The Swedish power sector is dominated by three main players: 1) The state utility company Vattenfall AB, b) the private enterprise E.ON Sweden AB and c) Fortum Oy (majority owned by the Finnish government).

¹⁹

Ref. <http://www.uic.com.au/nip39.htm>

Vattenfall has had the opportunity of purchasing a substantial portion of the thermal power generation capacity in Germany, and is today among the three largest operators on the German power market. For this reason Vattenfall is paying interest in European CCS projects and is strongly involved in projects like ENCAP, Castor, DYMAMIS etc. Vattenfall is the co-ordinator of the former project, and the operator of the Cottbus oxy-fuel pilot demonstrator at Berlin (refer Figure 1).

Figure 25: Aggregated CO₂ emission per sector in Sweden in million tonnes per year (Mtpa) totalling 58.48 Mtpa by year 2000. (Source: CSB, Utsläpp av koldioxid 1993-2000)

According to Figure 25 the largest emission of CO₂ by sector are 1) the steel and metals industry and 2) the energy sector. Typical of these sectors are the relatively large production units that may serve as point sources for CO₂. In contrast, the other larger emitters like 3) the maritime sector and 4) the transport sector as well as ‘other’ are represented by several smaller point sources that will not be easily included in a capture and collection system for CO₂. However, the pulp and paper industry is usually represented by larger plants that may be considered significant point sources for CO₂. Hence, when considering by sector the major point sources for CO₂ in Sweden that could be subjected to CCS, as encircled in Figure 25, a potential of about 14 Mtpa is identified (as per year 2000).

2.2.5 European sources

In the UK a large number of power plants and industries emit more than 200 Mtpa CO₂. Ammonia and hydrogen plants produce 1.5 Mtpa purified CO₂. At Teeside an integrated gasification combined cycle power plant is planned that could produce 5 Mtpa CO₂ from 2010. In the Antwerp-Rotterdam area there are four major CO₂ point sources. These are 1 Mtpa CO₂ from BASF/Air Liquide’s chemical plants, 1.4 Mtpa CO₂ from a refinery in Rotterdam and hydrogen plants nearby, and the Yara ammonium plant in Sluiskil, the Netherlands, that produces CO₂ for the food

industry. In Brunsbuttel, Germany, Yara's ammonium plant emits around 0.7 Mtpa CO₂. In addition several cement plants produce significant CO₂ volumes. The iron and steel industry is another major CO₂ source. 2 Mtpa CO₂ could be available from a steel plant in Dunkirk, and 10 Mtpa CO₂ from a plant in Ijmunden, the Netherlands. Similar sources are found in Gent, Belgium, and other regions of EU.

As depicted in Figure 26 there is a high concentration of CO₂ emission sources in Germany (especially around the Ruhr area) and in Northern France as well as in England. There are also some significant sources for CO₂ emission towards the East – like in Poland. In comparison, the concentration of CO₂ emissions in the Nordic countries is rather limited, and the sources rather widespread.

Figure 26: Impression of CO₂ emission source around Europe according to a recent Teltek study. The columns identifies the various point sources by geographical location and amount (height). (Source: Haugen 2005).

2.3 Opportunities for geological carbon dioxide storage in Nordic countries

Carbon dioxide may be injected and stored in reservoirs deep in the ground. A disposal site of CO₂ must be at least 800 meter below the sea surface in order for the CO₂ to remain stable in liquid phase. It is also important that the geological structure is porous enough so that the liquid CO₂ that is pumped into the ground may disperse in the formation underground. This porous structure must be situated underneath a layer of denser species of rock, such as clay slate, so that the gas does not leak through up the porous layers. There are potential risks for groundwater involved since displaced brine could contaminate freshwater layers (see section 4). In addition – it is of foremost importance that the geological formation is not situated in areas prone to earth quakes. Crevices or dislocation in the geological formation should also be avoided in areas for CO₂ storage (Høst and Bøe 2001).

For the Nordic countries storage in aquifers is the most interesting solution, and a series of aquifers comply with the most important demand for security, and may therefore be used for CO₂ storage. Several aquifers have been identified within or near the Nordic countries: Whereas eight aquifers have been identified in Denmark (Figure 27), Finland has identified no geological storage opportunity so far. In Norway, large-scale capture and storage of CO₂ is already being carried out at a natural gas field in the North Sea (Sleipner) and injected into the Utsira formation. Around Sweden - as shown in Figure 31- one aquifer is spreading from south-west into northern Germany, and another one from south-east of Gotland towards Russia.

Furthermore, several aquifers are identified in central Europe, such as in Germany, Poland, Belgium, Great Britain and France.

The geological storage capacity of the North Sea area is assumed at 800 Gt of CO₂, whereof 500 Gt is offered within the Norwegian sector. In order to understand the storage capacity of such formations, a simple calculation based on the entire European emission of CO₂ reckoned at 3895 Mtpa according to EIA (EIA 2005), one may assume that 1/3 could be captured, collected and stored (i.e. 1.3 Gtpa). This means that the entire CO₂ collected from Western-European sources could be fed into these formations continuously for more than 600 years, or almost 400 years just in the Norwegian sector.

2.3.1 Denmark

In 2003 the total emissions of CO₂ in Denmark was 58.6 Mtpa (EIA 2005), and according to GEUS about 36 % stemmed from power generation (GEUS 2000), which is the most interesting part when considering geological storage of CO₂.

The storage possibilities beneath Denmark and Germany will not be at free international disposal, but it is assumed that they most likely will be exploited internationally.

The Danish underground may be divided in two parts – the Danish part of the so-called Central grave and the Danish Basin. In the Danish Basin the possibilities of storage is in deeper sand stone layers (GEUS 2000). In Figure 27 the locations of the potential storage sites underneath Denmark is shown. In Figure 28 a geological cross-section of the underground north-east of Århus is presented to illustrate the special geological structures in Denmark.

Figure 27: Locations in Denmark with potential storage capability in deeper sand layers. (Source: GEUS 2000).

Figure 28: Geological cut-through the underground north-east of the Danish city of Århus.

So far eight small aquifers have been identified within the Danish territory, and the total storage capacity is assumed to be in the range of 10 Gigatonne CO₂. This storage capacity corresponds to roughly the demand of the Danish power industry over the next 400 years (at current load).

2.3.2 Finland

Mineral carbonation appears to be the only option for CO₂ storage in Finland, as the country has huge resources of natural magnesium silicates and waste materials. Products such as PCC (precipitated calcium carbonate) may be produced from slag from iron and steel industry.

The advantages of mineral carbonation for long-term CO₂ storage is deemed to be:

- Storage capacity
- Long retention time.

Disadvantages:

- Large mass flow rates of minerals
- High energy demand (15-20 Euro/t versus 1-13 Euro/t with aquifers).

Geological storage sites:

In response to the option for long-term storage of CO₂ underground, Finland, has so far not reported any geologic formations that are suitable for underground CO₂ storage. Hence, in the event of future CO₂ capture, the captured CO₂ must be exported. As the larger point sources for CO₂ are consistently situated in coastal areas, the option exists to transport the captured CO₂ on board ships.

The best option for long-term storage of CO₂ in Finland, however, is via mineral carbonation. For instance, the CO₂ captured from the Finnish pulp and paper industries could be transported in a pipeline to a carbonation facility. Taking the size and the location of the point emitting sites of the pulp and paper mills, a suggestion for a CO₂ grid was proposed by Teir (Teir 2004), as appears in Figure 29.

Figure 29: CO₂ emissions from selected plants in Finland in 2000. The figure shows the suggested CO₂ pipeline grid (dotted lines) and the existing natural gas distribution system. The red dots indicate the larger CO₂ emitters, and the two blue dots represent mineral storage sites (Source: Raiski 2004)

2.3.3 Norway

Figure 30 presents a map of the continental shelf and the Norwegian Sea (Høst and Bøe 2001). CO₂ may be stored either in existing oil and gas reservoirs (presented in green and red) or in water-filled aquifers. Examples of aquifers are the Sognefjord, Fensfjord and Krossfjord formations (one aquifer) outside the west coast of Norway, and the Tilje formation, as well as in a sedimentary rock type in the Fro Sea.

Figure 30: A map showing the continental shelf and the North Sea and the Norwegian Sea. CO₂ may be stored in existing oil- and gas fields (presented in green and red) or in water-filled aquifers (Source: Høst and Bøe 2001).

The map is a result of the GESTCO project (Gestco). What has been revealed is that no geological structures suited for CO₂ storage have been identified in the mainland of Norway.

The point sources for CO₂ in the Grenland area (south-eastern part of Norway) have an interesting location due to their proximity to Skagerrak. However, Skagerrak has so far not been opened for oil or gas activities, which implies a lack of seismic information on this area.

In the North Sea there are several possible geological formations assumingly well suited for CO₂ storage (Høst and Bøe 2001). Depleted oil- or gas fields are well suited for CO₂ storage.

The Utsira formation is an enormous saline aquifer, being the first full-scale storage site for CO₂ in the world to operate commercially. Since 1996 1 Mtpa CO₂ has been fed into this formation.

2.3.4 Sweden

Assessment studies of storage options in Sweden have identified two aquifers suited for CO₂ storage as shown in Figure 31. The one stretches from south-western Skåne, whereas the other one is located southeast of Gotland and stretched east-wards towards Kaliningrad (Russia).

According to Elforsk (CSLF 2006) the storage quality of the first-mentioned aquifer is good, while the second one is more uncertain. It is further believed that no more aquifers are likely to be found beneath Sweden as most of the ground is precambrium rock.

The formation beneath Skåne spreads all the way to Denmark and Germany. This formation is assumed to have a storage capacity of 1-3 Gtonne CO₂. It should be kept in mind that there is a need for research concerning the seismic conditions in this area.

For Sweden to be able to have CO₂ storage sites available, it may be required to study the Skåne aquifers in more detail, as the existing conventions of the law of the sea is an obstacle for countries such as Sweden to explore the North Sea aquifers.

Figure 31: Potential underground storage sites for CO₂ within the Swedish territory (Source: Lövgren 2004)

2.4 Linking carbon dioxide sources and geological storage sites in Nordic countries

As a part of the Chalmers Environmental Initiative (Kjærstad and Johnson 2003) a project has been carried out focusing on the possible future ways for a European power-plant infrastructure. The main focus in this study was carbon sequestration in general, and large scale introduction of

CO₂ capture and storage in particular. The main output from this project was a GIS (Geographical Information System) database of the existing power plant infrastructure covering the following countries:

- EU except Greece and the new Central Eastern European member states (CEES)
- Norway
- The Czech Republic
- Switzerland

The database is divided further into the following sub-databases:

- Power plants
- Coal fields
- Gas and oil fields
- Storage sites

This comprehensive database comprises data from approximately 700 power plants with capacities more than 100 MW. Figures from year 2001 are used, both for production and CO₂ emissions. Figure 32 presents an overview of the GIS database content, with plots on the map divided between power plants (blue dots) and storage sites (purple, yellow, green and black dots).

Sharman et al. further present the possibility of collecting CO₂ from on-shore power plants and other industrial installations to be used for EOR from mature oil and gas fields. And, a CO₂ infrastructure located in the North Sea Basin between 55°N and 62°N has been indicated in Figure 32. Sharman et al. present the case that this CO₂ infrastructure could deliver and sequester up to 40 Mtpa CO₂ from industrial installations around the North Sea Basin while producing up to 120 million barrels per year incremental oil which would otherwise be permanently lost after decommissioning (Sharman et al. 2003).

In Figure 33 the pipeline shown as a red line may serve as a collector of CO₂ from nearby sites both east and west of this line, i.e. from large CO₂ emission sites on the Norwegian continental shelf and the UK sector, respectively. Larger clusters of CO₂ emitters may effectively access this main pipeline through common pipelines. Other on-shore stationary CO₂ sources discussed in earlier chapters of this report may also be collected and routed to this trunk pipeline, both from Norway, UK and Denmark – all situated around the North sea Basin.

Figure 32: Schematic illustration of the database with respect to power plants (blue dots) and various types of storage fields/sites (purple, yellow, green and black-crossed dots). The picture is somewhat simplified (Source: Kjærstad and Johsson 2003).

Figure 33: A trunk CO₂ pipeline up the Norway/UK median (Source: Sharman et al. 2003).

Summarising the CO₂ and CCS in the Nordic perspective

As has been explained in the previous part, the assumed capture cost may differ somewhat from study to study depending on technology specification, plant size and further presumptions made for each case. The deviation is also an expression of uncertainty of such cost estimates, as no plant has been built at full scale so far. Hence, as basis for several ongoing EU-FP6 projects, 50-60 €/tonne CO₂ has been assumed as the current cost level, whereas a cost reduction of 50% has been targeted, thus suggesting that 25-30 €/tonne CO₂ is within reach.

According to “IPCC Special report on carbon dioxide capture and storage” (IPCC 2005) the cost of electricity generation will increase by approximately 40-70 % for a modern natural gas-fired combined-cycle power plant (state of the art) using an amine-based post combustion scrubber.

The investment cost of a large power plant may be split in the following parts:

1. Power plant	50%
2. Capture train	35-40%
3. Infrastructure	10-15%

The IPCC (2005) report presents an overview of factors that affect the CO₂ capture cost. Among the main findings the following mention has been given:

- Technology must be defined before firm cost assessments can be made. The reason is that the cost may vary widely with the capture approach and technology as well as the kind of power system (or process) that is subjected to carbon capture;
- A system boundary must be drawn;
- The time frame and maturity of technology must be set; and
- The assumptions must be pre-defined or adjusted as appropriate.

When considering capture cost one should keep in mind that the technical attractiveness may depend on the fuel. For instance will the flue gas from coal-fired power plants contain typically 12-14 vol% CO₂, whereas the flue gas from natural gas-fired power plants contains only 3-4 vol %. On the other hand the flue gas from cement kilns and iron and steel works may contain as much as 20-30 vol% CO₂. Hence, the unit cost of captur-

ing CO₂ per tonne removed from a flue gas must be lower with coal than with natural gas.

The economic advantages for capturing CO₂ from coal-fired power plants post combustion compared with natural gas power plants may be summarized as follows:

- CO₂ content of the flue gas from a coal-fired power plant is 3-4 times higher than with natural gas;
- Plant-efficiency of modern coal-fired plant: Typically 45% (LHV);
- Plant-efficiency of modern natural gas-fired plant: 57% (LHV and combined cycle, state of the art); and
- CO₂ capture rate: 90 % with natural gas, 80% with coal.

Hence,

-
- The volume of CO₂ in a flue gas from coal/natural gas is typically 2/1;
- Investment cost for infrastructure is higher with coal per unit CO₂ captured.

In addition:

- The oxygen content in the flue gas with natural gas (combined cycle) increases the heat required for amine regeneration. And, likewise, the solvent is prone to decay faster. Hence, the operating cost per tonne CO₂ captured is prone to become higher with natural gas.

The main CCS cost is attributed to capture and compression of the CO₂. The CO₂ transport cost, however, will depend on several factors, such as volume, distance, soil type, terrain, density of population, and should be kept in mind when considering location of storage versus capture.

Furthermore, it seems obvious that the option of EOR/EGR is a main driver in current CCS projects since both Statoil/Shell and BP have announced that the first CCS plants to be built are likely to be motivated by the enhancement of oil and gas production from offshore reservoirs.

In Table 7 the major CO₂ sources that are identified for CCS, and the total CO₂ emission per year (2003) - in total and in percentage - are listed together with the identified CO₂ sink capacity and possible feed time (years) for the Nordic countries.

Table 7: Identified CO₂ sink capacity and amount of collectable CO₂ for storage by country.

Country	Major CO ₂ sources identified (Mtpa)	CO ₂ emission, year (as per 2003) Mtpa	Major CO ₂ sources as part of total CO ₂ emissions%	CO ₂ sink capacity identified (Gtpa)	Feed time (sink capacity/major source) Years
Denmark	~20	58.6	34	10	500
Finland	~5	54.2	9	0	0
Norway	3.5-16.4	45.0	8-36	500	30000-140000
Sweden	~14	55.7	25	1-3	70-210

Mtpa denotes million tonnes per annum. Gtpa denotes gigatonnes per annum (i.e. 1000 Mtpa)

List of abbreviations

Annex I	Industrialized countries as defined in an annex to the Climate Convention (UNFCCC).
CCS	Carbon Capture and Storage of CO ₂
CDM	Clean Development Mechanism
COP	Conference Of the Parties (to the Climate Convention; UNFCCC)
CO ₂	Carbon dioxide
CSLF	Carbon Sequestration Leadership Forum
EOR	Enhanced Oil Recovery
EGT	Enhanced Gas Recovery
ENGO	Environmental Non Governmental Organization
ET	Emissions Trading
EUA	EU Allowance (permit unit in EU's emission trading system; 1 EUA = 1 ton CO ₂)
IEA	International Energy Agency.
IPCC	Intergovernmental Panel on Climate Change
Gtpa	Gigatonnes per annum (i.e.1000 Mtpa)
JI	Joint Implementation
MOP	Meeting of the Parties (to the Kyoto Protocol)
Mtpa	Million tonnes per annum
MW	Megawatt
MWe	Megawatt electric power (net output)
NOK	Norwegian crown (7.94 NOK = 1 Euro as of 27 June 2006)
OSPAR	Oslo-Paris Convention
ppmv	Parts per million by volume
RD&D	Research, Development and Demonstration.
tpa	tonnes per annum
UNFCCC	United Nations Framework Convention on Climate Change

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Samandrag

Fangst av CO₂ frå industrielle prosessar og geologisk lagring kan bli eit viktig tiltak for å redusere menneskeskapte utslepp av CO₂. Denne studien gjev ein oversikt over status for CO₂ fangst og lagring (CCS) i eit klimaperspektiv, og spesielt når det gjeld utsiktene for CCS i dei fire nordiske landa Danmark, Finland, Noreg og Sverige.

Etter at CCS vart lansert for om lag to tiår sidan har mange forskings- og utviklingsprosjekt blitt gjennomført - i tillegg til nokre demonstrasjonsanlegg, spesielt det siste tiåret. Denne studien gjev ein oversikt over initiativ og prosjekt som er i gang.

Studien presenterar statusen for CCS i tekniske, økonomiske, institusjonelle, og miljømessige termer, i tillegg til ei vurdering av publikum si haldning til denne teknologien. Dei tekniske aspekta som er diskutert er fangst av CO₂ og ekstra energibruk, fangstkostnad i eksisterande og nye anlegg, kostnader knytt til transport, og samanhengen mellom storleiken på CO₂-kjeldene og fangstkostnaden. På den institusjonele sida blir statusen til CCS i det globale klimaregimet drøfta.

Den andre delen av rapporten presenterar ein oversikt over større stasjonære CO₂-kjelder og tilgangen på eigna geologiske formasjonar i nordiske land. Utsiktene for samankopling av kjelder og lagringsplassar blir også drøfta. Det finst ikkje så mange store stasjonære CO₂-kjelder i den nordiske regionen, men mange fleire i den større nord-europeiske regionen. Lagringskapasiteten i Nordsjøen er venteleg stor nok til å ta i mot CO₂ frå vest-europiske land i meir enn 600 år. I tillegg finst det åtte mindre geologiske formasjonar i Danmark og to i Sverige. I Finland har ein ikke påvist eigna lagringsplassar.

Oppsummert finst det eit interessant potensiale for ein CCS verdikjede frå fangst til lagring i den nord-europeiske regionen og rundt Nordsjøen som er basert på infrastruktur- og lagringskomponentar i dei nordiske landa.